Last Updated: *August 18, 2015*

Documentation on adjustments to the Draft Version of the Public Tool to produce the Final Version of the Public Tool
(Proceeding R.14-07-002)

Energy Division has contracted with Energy and Environmental Economics, Inc. (E3) to develop a 'Public Tool' that will allow parties to test various options for a successor to the existing net energy metering (NEM) tariffs, following Public Utilities Code 2827.1. The final version of the Public Tool was released on June 4, 2015. Revised versions of the final Public Tool were released on June 17, 2015 and July 20, 2015. Information on the final version of the Public Tool, along with information regarding the development of the tool, is available here.

This document provides information for stakeholders on questions posed on functionality of the draft version of the Public Tool, calculation errors identified in the draft version of the Public Tool, and subsequent changes made by E3 to the Public Tool in order to produce the final version of the Public Tool. Items highlighted in yellow are new additions from the previously posted version of the document.

- Section One contains a list of questions submitted by parties on the draft version of the public tool, with responses from Energy Division/E3 staff.
- Section Two contains a list of calculation, or labeling, errors that were identified in the draft version of the public tool, with a description of how these errors impact the results.
- Section Three contains a list of the changes that were made to the Draft Tool to produce the Final Tool.

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Section One: This section provides a list of questions on the draft version of the Public Tool submitted by parties along with responses from Energy Division/E3 staff

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1. How are small commercial customers defined?

Small commercial customers are commercial rate schedules that currently do not have a demand charge.

2. How does the model treat multi-family dwellings in the ZNE world?

The public tool uses a small number of Zero Net Energy (ZNE) bins for each utility. None of these bins include multi-family dwellings.

3. I understand that interconnection costs could not be added in the analysis because there is no "per customer" number that you could use. Is there a way to add interconnection costs on a non-customer-specific basis, at a later point in the calculations?

Interconnection costs are considered in the model and can be charged either to participating customers or all utility customers in the "Key Driver Inputs" tab of the public tool. The specific values used for interconnection costs can be found on the RR Inputs tab starting at row 404. They are incurred on a "per installation" basis, which is equivalent to a "per customer" or "per account" basis.

4. Why is the relative difference between without and with DER significantly smaller for PG&E than for the other utilities?

In the case presented at the workshop, PG&E's average rates are forecast to be lower than those of the other utilities. This drives fewer adoptions and a smaller difference between baseline rates and rates with DER.

5. Does the definition of "DER" include EE and DR?

No. Distributed Energy Resource (DER) refers to eligible customer-sited renewable generation modeled in the public tool including: solar PV, solar PV + storage, wind, biomass, biogas, and renewable fuel cells.

6. Please provide an explanation of how the exports to the grid are dealt with in the 'Share of Cost of Service' (COS) calculations.

The 'Share of Cost of Service (COS)' is calculated as the net customer payments to the utility divided by the net cost to serve customers considering all usage and all generation that occurs on the customer's premise including exports. Exports are treated as 'negative consumption' for the purposes of the COS calculation. For example, the $/kWh cost of service "credit" for exports will be equal to the export consumption shape times each of the cost components of the cost of service calculation.

To determine revenue allocated to customer segments, calculations are performed at the customer segment level, not at an individual customer level. Exports to the grid reduce customer segment consumption as does DER output that is "consumed" behind the meter. Exports to the grid will therefore reduce customer segment marginal cost responsibility for energy, and potentially for generation, grid transmission, and subtransmission capacity (to the extent that the exports are coincident with the system peak or customer segment diversified peak). Distribution and Primary peak demand are not reduced for DER output, regardless of whether the output is "consumed" behind the meter or exported.

7. How were NBCs treated in 'Share of Cost of Service' (COS) calculations?

The draft version of the Public Tool allows non-bypassable charges (NBCs) to be collected in a variety of ways, enabling users to test the impact from participants avoiding or not avoiding NBCs. The impact of the user's selection is included in utility bill. In all cases, the NBCs are included in the cost of service (COS).

8. How were interconnection costs treated in 'Share of Cost of Service' (COS) calculations?

The draft version of the Public Tool allows interconnection costs to be paid upfront by participants or included in the revenue requirement and collected from all customers. This selection is made on the "Key Drivers" Tab. The impact of the user's selection affects rates. For example, utility bills are higher if interconnection costs are included in the cost of service and paid by all customers rather than collected from the NEM customer.

9. What role do avoided costs play in the 'Share of Cost of Service' (COS) calculations?

Avoided costs that are calculated for the purposes of the Standard Practice Manual (SPM) cost tests are related to, but different, than the scaled marginal costs used in the COS calculations. Some of the underlying marginal avoided costs, such as the marginal avoided cost of energy are the same. Other avoided costs, such as the marginal generation capacity, are calculated differently to allow for the user to select their own resource balance year, for example.

10. What role do avoided costs play in the calculations that allocate revenue requirement to customer segments?

The calculations that allocate revenue requirement to customer segments use utility General Rate Case (GRC) settlement marginal costs in all cases except marginal energy costs. Marginal energy costs are the same values used in SPM cost tests and COS calculations and are calculated in the Tool. The allocation calculations use proxies of the peak demand methods used by each utility in their revenue allocation process.

Marginal costs are used to allocate revenues to customer segments following current utility practices. Revenues are allocated in three categories: Generation revenue requirement is allocated based on the sum of generation capacity marginal cost revenue responsibility (MCRR) and energy MCRR. MCRR is the product of unit marginal costs and marginal cost determinants, such as energy use by time of use (TOU) period or peak capacity. Total subtransmission plus distribution plus customer service revenue requirement is allocated to customer segments based on the sum of the subtransmission MCRR, primary capacity MCRR, distribution capacity MCRR, and customer-related MCRR. Grid or Federal Energy Regulatory Commission (FERC) jurisdiction transmission is allocated directly to customer segment, with no need for the calculation of a grid transmission MCRR.

11. If there were more documentation available around the adoption model, including the source or derivation of the payback curve, that also would be extremely helpful.

The webinar we gave on this topic on December 2, 2014 is available here: http://www.cpuc.ca.gov/PUC/energy/DistGen/NEMWorkShop04232014.htm

12. How many hours of storage does this model assume for the pricing tab on AF31? Was it four hours?

The assumed storage duration is 3 hours. This number was chosen based on the values in Table B-30 in the DOE/EPRI 2013 Electricity Storage Handbook in Collaboration with NRECA report.

13. Is there an output tab that displays the average size of the PV and storage systems deployed in a run?

The results tab displays an aggregate "DER Size Breakdown" for the systems that were adopted in a particular run (AE148:AE150). These small, medium, and large size breakdowns are computed relative to a customer's annual load (small is 33% of annual gross usage, medium is 66% of annual gross usage, and large is 100% of annual gross usage). In the adoption outputs tab, there is a detailed list of all systems that were adopted including the size in kW. All storage systems are sized to have a discharge capacity equal to PV nameplate capacity.

14. What benefits does the "grid benefits" operation of storage include?

"Grid Benefits" operation includes the following benefits: subtransmission, distribution, energy, generation capacity, losses, RPS energy, and ancillary services.

15. Is there a way to deploy an excel solver to produce rate designs that keep payback at year 7 or below while maximizing avoided cost benefits?

No, the iterative nature of the model is not set up to run in this way.

16. We ran a case retaining the ITC at 30% and saw a decline in adoptions in 2017. Why did this occur?

We think this result is due to the data that we used to seed the model with pre-2017 adoptions. We are looking into this result and will let parties know if a change should be made in the 2015-2016 seeding data. We think that the 2017 result is correct.

17. The adoption rate from 2019 for PG&E appears flat. Intuitively, since solar prices continue to decline and rates continue to rise in the model after 2017, would we expect that the economic proposition driving customer adoption would result in continued growth in adoption rates?

This result is a function of the S-curve methodology the model uses to forecast how fast market adoptions approach the expected ultimate saturation penetration. With this approach, an unsaturated market will see rising incremental adoptions, one that is approaching saturation has declining annual incremental adoptions, and a fully saturated market would have no incremental adoptions. Similar year on year adoptions can occur even as rates increase and costs decrease past the mid-point in the S curve as the market approaches saturation. In this case, the improved payback 'makes up' for the natural slowdown as saturation increases.

18. Should cell I551 (and j552, k553, … AV591) be equal to zero?

No. Depreciation begins when property is placed in service.

19. Should cells J877 and K877 contain values?

No. SDG&E's generation net plant figure is at year-end 2013. If these cells were non-zero the accumulated depreciation for years 2012 and 2013 would be double counted.

20. Are all the grid charges for the DER Options ($ / kwh exported, $ / nameplate, etc.) scale with the default rates?

Yes.

21. Is the $ / Nameplate kW Grid Charge for DER a $ / kW / Month, or $ / kW / Year input?

$/kW-yr. We will fix the labeling in the final version of the Public Tool to make this clearer.

22. I set up a case with all behind the meter consumption at retail rate, while all exported kWh are given a fixed FiT rate of $0.87 / kWh. This was accomplished by (a) set

"Compensation Structure" to "Retail Rate Credit + Value Based Export Compensation" (b) set ALL fields for "Value-based Compensation" to "No", and kept the societal adders empty (c) set "Grid Charge (exported DER generation)" to -0.87. Is that the right way to make the model calculate results with a user-defined FiT rate instead of a model calculated value based FiT rate?

We recommend modeling a flat feed-in tariff (FiT) by setting all fields for 'Value-based Compensation" to "No" and putting the $0.87/kWh value in the Societal Value Adder. You can allow this value to increase, decrease, or remain flat over time by entering various nominal escalation rates. Entering a negative grid charge will not achieve the same result. If you select value-based compensation, the model will not calculate compensation due to grid charges or any other bill savings. The same effect holds for exports under an asymmetrical rate. If you select "Full Retail Rate Credit" for compensation structure and add a negative grid charge, the payment will be incremental to reductions in the variable portion of bills. Moreover, a negative grid charge will not hold at all if it causes a customer's annual bill to become negative. Any negative grid charge benefits beyond a $0/yr total bill will be ignored.

23. Why are forecasted annual incremental kW adoption falling off sharply on all results post 2020 / 2022? I checked all the results after model run, and I see that the market was nowhere near saturation at 2025.

Many of the most lucrative bins are approaching saturation penetration by 2020/2022. The penetration by bin can be found in column H of the Adoption Outputs tab. Keep in mind that full penetration is not 100% but rather the technical potential %'s found in the Advanced DER Inputs tab. Also, the S-curve methodology used in the model adoption logic predicts the highest annual installation years will occur when a market or bin is 50% saturated. Once a market or bin surpasses this penetration levels, adoptions will continue to increase, but at a slower pace as it approaches full saturation. For more information on the adoption and S-curve logic, please see the December webinar that focused on this part of the model (link can be found at http://www.cpuc.ca.gov/PUC/energy/DistGen/NEMWorkShop04232014.htm).

24. I see that if we change RPS levels (33% to 40% to 50%), the amount of kWh discharged from battery storage also increases. Why is this?

The annual kWh discharge for storage dispatched for grid benefits is higher at higher Renewable Portfolio Standard (RPS) levels because there is more opportunity and value for performing energy arbitrage. There are more hours with overgeneration and curtailment in the higher RPS levels, while the peak daily usage net of non-dispatchable generation is not substantially reduced (i.e., the "duck curve"). RPS level does not affect dispatch of any individual storage system dispatched for TOU arbitrage or demand charge minimization, although it may affect aggregate storage adoption through rate level impacts.

25. The forecasted incremental adoption kW for 2015 and 2016 seems to be fixed. By changing ITC levels for 2017 and forward, it does not have any impact on adoption kW

for 2015 and 2016. But I would think the forecasts for 2016 would have a portion of "gold rush" last minute adoptions build in to take advantage of the ITC before it decreases, and that "gold rush" should have shifted to 2017 and further if I changed ITC so it does not decrease in 2017. Is E3 assuming there is no "gold rush" in 2016?

Correct, there is no "gold rush" logic in the model. We fix 2015 and 2016 kW adoption to be based on the existing rate structures. We believe that this is appropriate because, in order to simplify the model, we assume that the new residential rates and the successor tariff(s) to NEM do not go into effect before 2017. 2015 and 2016 adoptions do incorporate the full benefit of the Federal investment tax credit (ITC).

26. In the model, how exactly would forecasted DER installation from a previous year affect RR for the current year, and forecasted kWh sales for the current year? For example, does 2018's RR take into account under-collection / cost shift from the DER installed in 2017 and before, and add that under-collection to a base 2018 RR? Does the kWh generated from 2017 DER adoptions change forecasted kWh for 2018, and thereby impact rate design for 2018?

Yes, incorporating the cost impacts of DER and any associated cost-shift is a key function of the model. For example, in 2020 the revenue requirement incorporates all avoided costs of DER on the system through 2019, although it does not include a forecast of 2020 DER adoption. Also, 2020 billing determinants incorporate all DER on the system through 2019. Using the total revenue requirement and total billing determinants, the model calculates rates that fully recover the revenue requirement and necessarily incorporate any cost-shift due to DER.

27. Please look at Slide 52 from the Workshop slides. The Without DER CoS % for PGE and SDGE are pretty fairly even across different classes, while SCE's without DER CoS jumps all over the place from 120% at Res, to 90% at Small Commercial, back to 120 in Large Commercial, dropping all the way to 59% for Industrial. Why is this?

In reviewing the results shown on Slide 52, we recommend that Parties focus on the changes in CoS between the "without DER" and "with DER" cases. For that comparison, the single driver of change is the introduction of DER. Trying to interpret the differences in "without DER" across classes and utilities is more challenging. There are multiple changing drivers of these differences, including:

1. Differences in utility marginal costs
2. Differences in utility revenue requirements by functional component that change the relative weight of marginal costs in the full cost of service (different EPMC factors by function)
3. Differences in the stylized customer-segment rates (which are aggregations of multiple rate schedules)

4. Differences in characteristics of DER participants within the customer segment and non-participants within the segment, which is partially a function of the customer-segment stylized rates

Because of the many factors that contribute to differences in "without DER" CoS recovery between classes and utilities, it is not practical to provide a simple description of the exact drivers of the differences. Moreover, the dynamic updating of the model marginal costs, revenue requirements, and rates for adoptions within each utility and across all utilities makes it difficult to isolate any particular driver (other than the with and without DER effect for each customer segment).

That said, we provide two examples that identify the main drivers of why the "without DER" CoS recovery is lower for SCE's small commercial and industrial classes than those of PG&E and SDG&E.

In 2020, small commercial customer-related costs are about $3.41 per day for PG&E and $1.19 per day for SCE. Turning to the current retail rates, we see customer charges for small commercial of 37 cents per day for PG&E and 96 cents per day for SCE. This indicates that PG&E is collecting a far smaller share of its customer costs through the customer charge than SCE. Therefore, similar to the residential class, the larger PG&E customers would be paying more than their cost of service. Since PG&E participants are far larger than the customer segment average, a CoS% far above 100% is to be expected. SCE, on the other hand, has a customer charge that is close to its cost of service. Moreover, while the SCE participants are larger than the segment average, they are only about 2.5 times the average, while PG&E's are about 7 times the average. Given the small difference between customer cost of service and rates, and the smaller difference in size, the customer size impact will be minimal and the CoS% ratio is driven by other factors such as the differentials between the summer and winter energy rates and the marginal energy costs. SDG&E's small commercial fixed cost collection falls between those of SCE and PG&E. SDG&E's small commercial energy charges are also not time-differentiated, which is contributing to higher SDG&E participant CoS.

The low % COS recovery for SCE industrial participants is driven by participant usage differing substantially from non-participant usage. The result is most likely due to insufficient data and small sample bias. There were very few industrial customers in SCE that adopted NEM through 2012, and the few that did had very low usage relative to the class average.

While these examples are not comprehensive in explaining each number on the table, they do illustrate the impact of some of the numerous factors that can drive the CoS % recovery results (mainly marginal costs, EPMC factors, participant characteristics, tariff design).

28. One surprising result from the draft Public Tool is that the future escalation in SCE's and SDG&E's retail rates is much higher than the growth in PG&E's rates. See Slide 28 from the E3 presentation at the March 30 workshop. SCE and SDG&E average residential rates double by 2035 and even in 2025-2030 are 30% to 50% higher than PG&E's rates. This trend

appears to be independent of the amount of DER installed. We have the following questions about elements of the Revenue Requirements model that appear to be driving that result.

a. The Public Tool's stated assumption for escalation in Distribution and Generation O&M is with inflation (2%), but the actual annual growth rates for distribution and generation O&M, in the Revenue Requirements model, are 5% to 7% per year for sustained numbers of years. These high and sustained escalation rates can be seen at the following lines of the RR Calculations tab – 147, 418, 534, 705, and 820. What is the basis for this rapid growth in O&M expenses?

O&M is a function of inflation and plant in service. As an example, if O&M costs for a 1 MW power plant are $40,000 in 2015 then with 2% inflation they are $40,800 in 2016. If a second 1 MW power plant were added, 2016 O&M costs would be $81,600. The $81,600 figure reflects both inflation and changes in plant in service. To smooth the O&M trajectory, we may use net rate base inflation in this calculation in the final version of the Tool.

b. SCE's distribution capex in Line 363 ($2.1 billion per year) is also much higher than PG&E's distribution capex in Line 91 ($1.4 billion per year), even though the SCE data is for 2011 versus 2013 for PG&E. This appears to result in significant above-inflation growth in SCE's distribution rate base, until past 2030. What are the sources for the distribution and generation capex numbers used in the Public Tool, for all three IOUs?

For PG&E, E3 used A. 12-11-009, Appendix D, Tables 5A and 5C. We are updating SCE's figures with 2012-2014 data from SCE's 2015 GRC, SCE-10, Vol. 02, Tables I-1, II-7 and II-8, which will result in starting average annual distribution capex of $1.96 billion per year. For SDG&E, E3 used the 2016 GRC Direct Testimony of Jesse S. Aragon, Table SDGE-JSA-2. The Public Tool includes factors that users may apply to these figures if users wish to adjust capex projections beyond the first GRC period modeled.

c. What is the sources for the "Capex retired from rate base," for example in Line 476 for SCE? Why does SCE appear to retire $13.1 billion in capex from rate base in 2025 (column W)? Does this impact the revenue requirement?

Capex retired from rate base reflects capex that has been fully depreciated and has reached the end of its economic life. The $13.1 billion figure is the starting net rate base for SCE. It reduces gross capex by the amount of retired plant. It impacts only O&M cost escalation.

29. Generally, can we obtain more details on the assumptions and data sources used for the Revenue Requirements model?

These were provided in the presentation on 16 December 2014. The link to this presentation can be found here:
http://www.cpuc.ca.gov/PUC/energy/DistGen/NEMWorkShop04232014.htm

30. We have been having difficulty finding the retail rates that the Public Tool has been calculating. For example, the Detailed Rate Outputs section of the Results tab does not seem to work correctly. We input a TOU rate design as the default for residential, but it does not show up in this portion of the Results tab. Or we choose a 2-tier default residential rate, but this section of the Results tab still shows a 3-tier rate. Is there a problem here?

E3 has not experienced any issues with incorrect rates populating in the detailed rates output section. The model needs to be fully run with the new rate inputs for this output (and all other outputs) to work correctly. All of the detailed rate outputs are stored in the Rate Output Table tab.

31. What is the methodology and the documentation for the billing determinants data? There is a tremendous number of columns in the Billing Determinants database. How was that data generated?

Much of this information was provided in the presentation on 16 December 2014. The link to this presentation can be found here:
http://www.cpuc.ca.gov/PUC/energy/DistGen/NEMWorkShop04232014.htm

For each customer bin, DER technology, and DER system size, we used half-hourly generation and load data to calculate all billing determinants that may be required to determine bills in the Tool. Because there are a number of rate designs and compensation mechanisms available in the Tool, the database includes many different energy, capacity, and customer billing determinants that may describe gross usage, all DER generation, exported generation, net usage (measured as gross usage less all generation), or net usage excluding exported generation. All billing determinants are aggregated to an annual level (ex. monthly max demand is the sum of twelve monthly max demands).The Billing Determinants database also includes some general information about the representative customer bins, such as rate territory and customer segment.
Example billing determinants include:

- Energy usage in each TOU period
- DER generation in each TOU period
- Exported energy in each TOU period (based on half-hourly netting)
- Energy usage in each tier
- Maximum monthly demand (12NCP)
- Maximum demand in each TOU period
- Ratchet demand by season
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The following table summarizes the dimensions of the billing determinants that can be found in the file:

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Billing Determinant	Dimensions	Total #	Notes
TOU_kWh_allgen	x 9 TOU periods x 2 seasons x 3 sizes x 9 techs	486	
TOU_kWh_export	x 9 TOU periods x 2 seasons x 3 sizes x 9 techs x 2 netting	972	Hourly netting not used in Public Tool
TOU_kWh_net	x 9 TOU periods x 2 seasons x 3 sizes x 9 techs	486	
TOU_kWh_gross	x 9 TOU periods x 2 seasons	18	
	Subtotal:	1962	
Tier_kWh_net	x 4 tiers x 2 seasons x 3 sizes x 9 techs	216	
Tier_kWh_net_noexport	x 4 tiers x 2 seasons x 3 sizes x 9 techs x 2 netting	432	Hourly netting not used in Public Tool
Tier_kWh_net_plus_BTM	x 4 tiers x 2 seasons x 3 sizes x 9 techs	216	Not used in Public Tool
Tier_kWh_gross	x 4 tiers x 2 seasons	8	
	Subtotal:	872	
ann_kWh_allgen	x 3 sizes x 9 techs	27	
ann_kWh_export	x 3 sizes x 9 techs x 2 netting	54	Hourly netting not used in Public Tool
ann_kWh_net	x 3 sizes x 9 techs	27	
ann_kWh_gross	x 1	1	
	Subtotal:	109	
m_TOU_kWh_allgen	x 12 months x 9 TOU periods x 3 sizes x 9 techs	2916	
	Subtotal:	2916	
pk_kW_mos_net	x 3 demand tiers x 2 seasons x 3 sizes x 9 techs	162	Based on the demand differentiated customer charge proposed by SDG&E; no adjustments for netting
pk_kW_mos_gross	x 3 demand tiers x 2 seasons	6	
	Subtotal:	168	
pk_kw_TOU_s_m_net	x 6 months x 9 TOU periods x 3 sizes x 9 techs	1458	TOU-specific demand charges; no adjustments for netting; SCE only has 4 summer months
pk_kw_TOU_s_m_gross	x 6 months x 9 TOU periods	54	
	Subtotal:	1512	
pk_kw_monthly_net	x 2 seasons x 3 sizes x 9 techs	54	Sum of monthly max demands; no adjustments for netting
pk_kw_monthly_gross	x 2 seasons	2	
	Subtotal:	56	
pk_kw_rachet_net	x 2 seasons x 3 sizes x 9 techs	54	Single highest demand by season; no adjustments for netting
pk_kw_rachet_gross	x 2 seasons	2	
	Subtotal:	56	
ann_storage_discharge	x 3 sizes x 6 storage techs	18	For variable O&M calculations
nameplate_AC_kW	x 3 sizes x 2 non-dispatchable techs	6	
bin_id	x 1	1	
bin_weight	x 1	1	
customer_segment	x 1	1	
heat_code	x 1	1	
terr_comb	x 1	1	
CARE	x 1	1	
Accts	x 1	1	For select multi-family customers; not used in Public Tool
azimuth	x 1	1	
Util	x 1	1	
	Subtotal:	33	
	Total:	7684	

32. Does the added PV in the ZNE scenario include some amount of PV on those homes in absence of the ZNE policy or does it assume those homes would not have any PV without the policy?

The ZNE scenario assumes all new accounts have rooftop PV. It does not make assumptions about whether those homes would have had PV without the policy. In scenarios with no ZNE policy active, rooftop PV is adopted economically for new accounts.

33. How are parties able to share input files?

The 'Scenarios' tab in the Public Tool contains all of the saved user input scenarios. To share a saved scenario, parties can either save the full model or just the 'Scenarios' tab. Parties may copy and paste scenarios between tools. For example, if you copy rows 6 through 4601 of column F in one Public Tool and paste the values in any column (F through AD) of the 'Scenarios' tab in another Public Tool model, the 'Load Inputs' feature will treat the copied case as one saved directly. Note that the scenario inputs do not include inputs found only in the Revenue Requirement model.

34. Are there other incentives for GHG reduction that we could model in the Public Tool? For instance, can we add credit for increased production from bifacial panels with white cool roofs and a west facing format?

Users may add utility incentives in cells X32-AC49 on the Advanced DER Inputs tab. Because billing determinant data has been pre-processed, it is not possible to run scenarios with increased DER production.

35. Are the GHG reductions due to EV penetration modeled in the tool?

No. This is outside of the scope of the Public Tool.

36. Is there a way to get the tool to run netting scenarios other than half-hourly?

This is not possible since the billing determinant data is pre-processed. Due to time, budget, and model run time constraints, we were only able to pre-process the billing determinant data using half-hourly intervals.

37. Does the Tool net monthly for all compensation structures?

Netting of gross usage less generation for the calculation of exports and generation consumed behind the meter occurs on a half-hourly basis.

In terms of temporal granularity of other billing determinants and compensation, most of the Tool economics are based on annual totals that are not affected by temporal granularity, but the Tool uses billing determinants calculated monthly or seasonally as appropriate:

- Net and gross tiered energy billing determinants are calculated at a monthly granularity.
- Monthly max demand (kW, 12NCP) and demand-differentiated seasonal time-of-use billing determinants (months) are based on max half-hourly demand within each month.
- Ratchet demand is calculated on a seasonal basis.

Temporal granularity does not affect any other billing determinants or compensation.

38. References:

a) Where are the "high" price scenario inputs from?

b) Which report/analysis from EIA was used to develop the forecasted price decline?

c) Was the LBNL TTS report used for the >10kW prices? It doesn't line up.

a-b) The base and high price scenario inputs use the same starting $/W prices in 2014, but assume learning rates of 20% and 15%, respectively for soft costs and non-module hard costs. The global PV forecast used in conjunction with these learning rates came from the IEA (http://www.iea.org/Textbase/npsum/MTrenew2013SUM.pdf). Since the report only forecasts installation through 2018, E3 extrapolated the 2017-2018 global growth rate through 2025 to achieve a price forecast through 2025. Module costs decline via an E3 regression comparing price to global installed capacity which also is close to a learning rate of 20%.

c) Yes the LBNL TTS report was used for > 10 kW prices. Page 53 of the report (http://emp.lbl.gov/sites/all/files/lbnl-6858e.pdf) has these values.

39. Does the model convert DC (LBNL data) to AC or is it mislabeled? We note that for < 10 kW customers, the numbers in the table match the DC numbers in the LBNL report.

This is an error. The PV price input units should be $/kW-AC, and the default values should be divided by an AC-DC derate of 0.85. Thank you for making us aware of this issue. It will be fixed in the revised version of the Tool.

40. Are financing costs being added to the solar price inputs via the "Debt Interest Rate" and "After-Tax WACC" table Or anything else? If so, why? Will E3 add a function allowing a user turn this off (without manually changing the model)?

We are not clear what is meant by "financing costs." An appropriate return on invested capital is a necessary part of DER costs, therefore E3 will not add a function to enable a user to turn off after-tax WACC, debt or equity costs. Incremental financing costs such as reserve amounts or upfront fees are not included in the DER pro forma.

41. What is the reference for solar O&M expenses ($27/kW-yr)? (Which seems high.)

This value is an E3 estimate that was informed by multiple sources including some that were higher (http://bv.com/docs/reports-studies/nrel-cost-report.pdf) and some that were lower (http://www.nrel.gov/analysis/tech_lcoe_re_cost_est.html).

42. Please confirm our understanding of how a DER's avoided energy cost is calculated in the public tool.

a. Per the Dec 16, 2014 slide deck, market heat rates are "calculated using 2014 RPS Calculator methodology, shaped using 2014 CEC Title 24 Plexos hourly curves." We interpret this to mean that the public tool uses a simple stacking process to estimate the energy value of DER using data extracted from Plexos inputs/outputs.

This interpretation is not correct. The 2014 RPS Calculator stack is based on 12 monthly 24-hour periods (288 periods total). The TOU periods in the Public Tool require data for weekends and holidays. We used the Plexos curves to shape the stack data to account for weekend and holiday periods, such that the average scaling factor for each month equals 1.0 (i.e., over each month the heat rates equal those produced by the stack model). The Plexos curves were not used for any other function except to account for weekends and holidays.

b. The stacking process stacks different types of gas-fired resources that can be on the margin with different typical heat rates (HR) stacked from low to high HR. This HR stack is compared to a 24-hour representation of the net load of a month, where the net load is gross load-wind-solar (including DER solar) -nuclear-hydro, adjusted for with storage operation. The minimum HR in the stack is 6000 Btu/kWh. Q1: Is this correct? Q2. What heat rate is used during overgen or curtailment hours when must-run + minimum fossil exceeds the net load? 6000 Btu, 0 Btu, or something else? And what's the reason for the answer? Q3: have the heat rates at the low end of the generation stack been compared to recent market heat rates observed at similar levels of net load (where net load is defined as above)?

The stack serves gross load net of renewables, nuclear, hydro and CHP. Load is adjusted for basic utility-scale storage operation. The minimum heat rate that can be in the stack in 2050 is just under 6,000 Btu/kWh.

A heat rate of 0 Btu/kWh results during overgen or curtailment hours. Actual heat rates observed at similar levels of net load are 0 Btu/kWh because renewables are on the margin during these hours. Developers are assumed to be fully compensated via PPA prices for any energy that is curtailed.

c. Using this approach, the model calculates a marginal HR by hour for each of the 24 hours representing a month by comparing the net load in each of the 24 hours to that stacked gas-fired resources for that hour. The marginal HR for that hour is the HR of the last gas-fired resource needed to satisfy the load in the hour.

d. The model then calculates an average monthly HR for each of the 18 TOU periods using the 24 HRs for the month. Q4: is this a simple average HR for the month? Q5: where average prices are used to calculate avoided cost for a particular DER, Shouldn't these averages be weighted by the hourly output of that DER technology, since prices and DER output are correlated?

To match the Public Tool TOU periods, a simple average heat rate is calculated for each TOU period for each season (not month) for use in the revenue requirement.

The heat rates and energy prices by TOU period used in the Public Tool for avoided cost calculations are the average of the marginal heat rates and prices in the given TOU period. Coincidence of DER generation and energy prices are taken into account across TOU periods, but not within TOU periods. In order to capture as much granularity as possible, the Tool uses 12x18 TOU periods for calculating energy avoided costs.

e. The model seems to "profile" the monthly average HRs by TOU using scaling factors developed from Plexos simulations. Q6: Is this correct? How were these TOU scaling factors developed? Were they developed from the 2014 CEC Title 24 Plexos runs? If yes, how? Q7: Were the TOU factors calculated as the ratio between TOU and monthly average energy prices? Q8: Were the TOU and monthly average prices simple averages or DER output-weighted averages? Q9: What scaling factors are used for 50% RPS?

As described in the response to #1a above, TOU factors were developed to account for weekends and holidays. A TOU factor was calculated for each hour by month such that the average of the factors in each month equals 1. For example, if the heat rate in hour 1 = 9000 and the monthly average heat rate = 7500 then the heat rate factor in hour 1 = 9000/7500. Once the 8,760 factors were calculated, they were bucketed by TOU period and month and season.

The TOU factors are based on heat rates, not energy prices.

The TOU factors are not related to DER output, except as DER output may have influenced marginal heat rates.

Plexos data was not available for a 50% scenario. We used the 40% factors for RPS penetration above 40%. Note that the underlying stack heat rates account for heat rate levels related to RPS penetration and changes in stack composition over time.

f. Please provide the hourly energy or heat rate values used to calculate the TOU scaling factors (eg, if they were prepared from hourly energy prices and gas prices from Plexos, please provide those values, and the various steps used to calculate the scaling factors) Also, please provide a description of the assumptions used for the Plexos simulation or simulations if more than one Plexos run for say 33% RPS and 40% or higher RPS or DG levels. Also, please provide the hourly profiles of DERs used in these simulations.

E3 does not have access to the hourly profiles of DERs used in these simulations. Please contact the CEC for this information.

See attached file for the derivation of the scaling factors.

g. Did E3 validate the resulting DER avoided energy cost derived from this stacking process against the sumproduct of the hourly market prices and hourly DER generation used in the Plexos simulations? If no, how did E3 validate its stacking approach? Was any market data used to validate the model, for example, 1) comparing monthly averaged 24 hour profiles from recent Day Ahead Market runs with near-term price forecasts from the model to validate the general shape or 2) calculating a relationship between recent actual net loads (as defined here) and market heat rates to validate the generation stack?

The stack logic is the same logic used in RPS Calculator 6.0. It was implemented in the Public Tool to enable the modeling of directional changes in energy prices due to policy impacts (i.e., ZNE homes, RPS penetration, energy efficiency levels, electric vehicle penetration). Developing market energy price logic that takes into account the full range of drivers of power price levels, including transmission constraints, hydro levels and outages, was not possible due to the scope and budget of this project. The general shape of results comports with our expectations.

43. RPS Purchase Value Questions

a. Our understanding is that the RPS prices in the public tool are the same as the values used in the latest RPS Calculator 6.0. Is this correct?

Yes.

b. Also, our understanding is that E3 indicated, during a workshop on Feb 10-11, that the solar prices in the RPS Calculator are 25% too high and wind was 5% high, and both will be adjusted down. If our understanding is correct, when are the adjusted values going to be used in the Public Tool?

If this data is released prior to release of the final version of the Public Tool then it will be incorporated. Note that users may easily change RPS costs, by year and by technology type, if desired.

c. Please provide the explanation for the increase in RPS prices in 2017

Prices for RPS technologies that receive the federal investment tax credit (ITC) increase in 2017 because ITC is assumed to reduce from 30% to 10% in this year. Note that this is not dynamic with the user input for ITC for DER.

d. How does the public tool estimate RPS curtailments and what assumptions does it use to calculate RPS curtailments?

The Public Tool uses the same logic as that in the RPS Calculator version 6.0. See the Revenue Requirement model DM365:EY365 which calculates RPS overgeneration GWh.

e. How does the RPS curtailment affect the RPS purchase avoided cost? Our understanding is that when RPS Curtailment is coincident with DER production, there is a feedback between increased DER production and increased RPS curtailment, and that an adjustment accounting for this feedback would be captured in the RPS avoided cost, but couldn't find it where

Yes, this curtailment impact is included in the avoided costs (see rows 426 to 437 on the 'Avoided Cost Calcs' tab). In periods where marginal renewable generation is being curtailed, we assume that all incremental DER generation causes an equal amount of utility-scale renewable curtailment. This reduces the number of RECs associated with existing utility-scale RPS assets, which increases the amount of incremental RPS procurement required. We take overprocurement and banking into account when calculating incremental curtailment-related RPS costs. We also make a vintaging distinction. Under vintaged avoided costs, the curtailment-related RPS cost of a DER system is based on only the curtailment periods when the DER system is first installed. In the non-vintaged case, hours with marginal curtailment are updated annually.

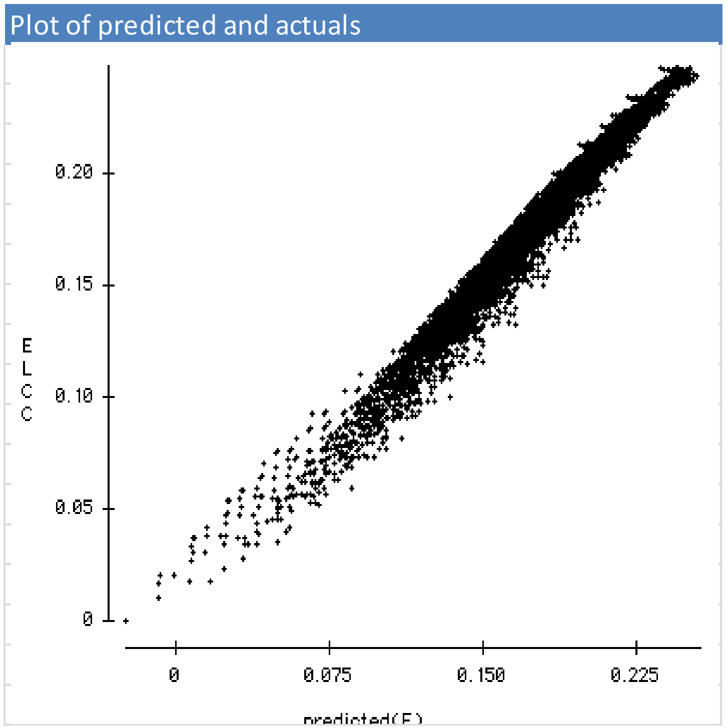
44. ELCC questions

a. From the December 16, 2014 workshop,

i. Non-Vintaged: Individual ELCC values for all vintages are updated every year as RPS and DER penetrations change. Q: Is this annual updated ELCC a marginal or average ELCC? Is this average or marginal ELCC the same for all technologies or is it different for all technologies? If these values are different by technology, how does E3 deal with the interactions between RPS technology ELCCs? For example, if the wind ELCC increases with higher solar penetration.

Average ELCC is used to determine the total contribution of all grid renewables and DER for resource adequacy purposes. Marginal ELCC is used to determine the marginal cost savings from new incremental DER that would be installed in that year. The ELCC is estimated using the following regression that includes interactions between technologies.

Regression results from DataDesk				
Dependent variable is:	ELCC			
R squared = 97.3% R squared (adjusted) = 97.3%				
s = 0.006107 with 9477 - 15 = 9462 degrees of freedom				
Source	Sum of Squares	df	Mean Square	F-ratio
Regression	12.9397	14	0.924263	2.48E+04
Residual	0.352895	9462	3.73E-05	
Variable	Coefficient	s.e. of Coeff	t-ratio	prob
Constant	-0.0252094	6.02E-04	-41.9	≤0.0001
Concentrating Solar	1.16489	0.01252	93.1	≤0.0001
Concentrating Solar with storage	1.114	0.01252	89	≤0.0001
PV - distribution	0.163944	0.00904	18.1	≤0.0001
PV- utilty grid scale	0.0973158	0.006237	15.6	≤0.0001
Wind - Coastal	0.473603	0.001537	308	≤0.0001
Wind - Inland	0.32548	0.001537	212	≤0.0001
Sqrt (PV - distribution)	0.37913	0.00411	92.2	≤0.0001
Sqrt (PV-distrib * PV-Grid)	-0.787186	0.01288	-61.1	≤0.0001
PV-Distrib * PV -Grid	-1.03846	0.07292	-14.2	≤0.0001
Concentrating Solar * PV-Grid	-4.65302	0.09126	-51	≤0.0001
Concentrating Solar * PV-distribution	-6.70313	0.1323	-50.7	≤0.0001
Sqrt (PV-Grid)	0.335386	0.003429	97.8	≤0.0001
Concentrating Solar with storage * PV-distrib	-1.20265	0.1323	-9.09	≤0.0001
Concentrating Solar with storage * PV-Grid	-0.890785	0.09126	-9.76	≤0.0001
Input values are percentage of annual system energy				



ii. Vintaged ELCC: DER receives its marginal ELCC value at the time of installation throughout its economic life. Is this marginal ELCC different by technology? If so, how is the interaction between wind and solar marginal ELCC considered?

Marginal ELCC is estimated for each technology. The marginal ELCC is calculated by incrementing the installed capacity for a technology by 1.0 MW and calculating the change in total ELCC. The interactive effects are captured by the regression formulation. The marginal calculation reflects all technologies forecast to the installed prior to that year, but only increments one technology at a time for its calculation. It does not jointly increment both wind and solar at the same time.

iii. What's the logic for not adjusting the non-vintage ELCC of DERs when more DERs are added?

The logic for not changing the marginal ELCC for previously installed technologies is that it would be the future technologies that are changing the ELCC. Therefore, the beneficial or degrading effects of those future technologies should be fully assigned to those future technologies. To spread the marginal impacts over past installations would underestimate the marginal impact of the future technologies.

45. When setting the total installed cost for storage at extremely low prices ($100-250), we're still seeing very little uptake. Why does this occur?

If users are seeing very little storage uptake, it is most likely due to poor customer economics. It is also possible that user inputs are causing some storage dispatch technologies to be disabled. Economic uptake of storage is primarily driven by compensation structures and levels, although load and generation shapes also contribute to customer economics. Specifically:

- For economic adoption of storage for demand charge minimization, load must be spiky enough to allow storage to effectively reduce peak demand (perform "peak shaving"), and demand charges must be large enough to allow savings to outweigh storage costs. The coincidence between peak demand and generation also impacts the relative benefits of storage, as PV generation may reduce demand charges without storage if peak demand is coincident with the generation.

- For economic adoption of storage for retail rate arbitrage and storage dispatched for grid benefits, retail rate or compensation ($/kWh) differentials must be large enough to outweigh capital and O&M costs of storage as well as efficiency losses (85% roundtrip). Because storage may only charge from PV generation, midday prices must be much lower than prices during some hours with little sunlight (i.e., early evening).

The Public Tool uses pre-processed storage shapes with embedded assumptions on retail rates and CAISO system load. If users define cases that cause actual retail rates and CAISO system load to differ substantially from these embedded assumptions, the Public Tool will disable some storage dispatch technologies. To ensure that storage dispatched for grid benefits is enabled, choose 'Less Daytime' EV charging and either the 'Default – Base' or 'Default – Low' EV forecast scenario. Storage dispatched for grid benefits is also eligible under similar user-defined EV scenarios. Storage dispatched for TOU arbitrage will generally be enabled if on-peak periods fall within the 4pm to 8pm period. To check whether storage dispatched for TOU arbitrage is enabled under specific TOU definitions, use the 'Check Storage Compatibility' button on the 'Advanced rate Inputs' tab.

46. What assumptions were made regarding the life of inverters and their replacement cost? I did not see an explicit breakout in the Public Tool worksheets "Advanced DER Inputs" or "DER Pro Forma".

Inverter costs are included in the initial PV capital cost and replacement inverter cost is included in fixed O&M.

47. Assumption on module efficiency trends in the forecast period. Appears a constant capacity factor was used but I could be mistaken.

Module efficiency is outside the scope of this analysis. An increase in module efficiency means a given area (m^2) of solar panels will produce more power, but this does not necessarily increase capacity factor since the nameplate capacity of the solar panels will increase as well. E3 captures the combined effects of all module pricing and efficiencies through $/W solar price inputs.

48. In the Public Tool workbook, the sheet "Advanced DER Inputs" referenced cost data from several sources including LBNL's Tracking the Sun report series. Tracking the Sun uses CSI data but they do filter for host owned vs 3rd party leases . Regarding PV cost data and forecast, how was this data used in the model?

The public tool uses PV capital cost pricing data ($/W) from LBNL's Tracking the Sun and runs this data through a financial calculator designed to mimic a 3rd party lease. The output of the financial calculator is a levelized cost ($/kW-yr) equivalent to what a customer installing solar would pay to the 3rd party. This levelized cost includes the impact of all subsidies, tax incentives/implications, and 3rd party financing costs.

49. Were any features of the adoption method outlined by PGE in their reply comments incorporated into the model?

No

50. How were storage profiles developed? If I start with a 5 kW/25 kWh pack will the shapes allow me to estimate net annual energy draw and peak impact coincident by IOU?

All storage systems modeled in the Public Tool have discharge capacities equal to PV nameplate capacity, 3-hour durations, and 85% AC-AC roundtrip efficiency. PV is restricted to charging from PV generation only.

Storage profiles were developed for each bin, PV size (small, medium, large), and dispatch scenario. The half-hourly heuristic dispatches aim to minimize energy bills or maximize grid benefits, depending on the dispatch scenario, given customer load and PV generation. For storage dispatched for grid benefits, there are three avoided cost scenarios that capture various RPS trajectories. For storage dispatched for TOU rate arbitrage, there are two TOU period definition scenarios. Storage dispatched for demand minimization assumes a monthly demand charge.

It is difficult, but possible to calculate aggregate storage discharge at the IOU level. The billing determinants database includes annual storage discharge (ann_discharge_kwh) by bin, PV size, and dispatch scenario. You can combine this information with actual storage adoption by bin, PV size, and dispatch scenario using column K ("Annual Additions # sys") in the 'Adoption Outputs' tab of the Public Tool to calculate aggregate storage dispatch.

51. How can I get the Tool to run on a Mac?

There are two lines in the VBA code that must be changed before the model can run on Macs. To access the code, open the Macro project window (FN+Alt+F11 on a Mac), and select Modules-> Module1.

In the rrPubExchange() subroutine, change:
Workbooks.Open Filename:=ActiveWorkbook.Path + "\" & RRMODEL
To:
Workbooks.Open Filename:=ActiveWorkbook.Path + Application.PathSeparator & RRMODEL

In the RunModel2017() subroutine, change:
Workbooks.Open Filename:=ActiveWorkbook.Path + "\Billing Determinants Database.xlsx"
To:
Workbooks.Open Filename:=ActiveWorkbook.Path + Application.PathSeparator & "Billing Determinants Database.xlsx"

With these updates, the model can run on Macs and PCs.

52. We input additional CO2 costs as an additional societal benefit, at the level of the Administration's Social Cost of Carbon, i.e. greater than the Base CO2 cost assumptions in the draft Public Tool. However, when we ran the model, these higher CO2 benefits did not show up in the Societal Test. This run assumed Bucket 1 treatment for DER RECs. Then we did a run with no Bucket 1 DER RECs, and the added CO2 benefits did appear in the Societal Test. What is happening here?

When DER receives Bucket 1 treatment for RECs, DER generation displaces utility-scale RPS generation at a rate roughly equal to one-to-one. Total renewable generation and total CO2 emissions remain roughly equal because the IOUs would procure more utility-scale RPS generation in the absence of DER adoption. When DER does not receive Bucket 1 REC treatment, DER generation only reduces RPS generation via the compliance obligation and reduces thermal generation otherwise. For example, under a simplified case with a 40% RPS and no banking or curtailment, 1 MWh of DER generation would displace 400 kWh of RPS generation and 600 kWh of thermal generation if DER does not receive Bucket 1 REC credit. If it does receive Bucket 1 REC credit, 1 MWh of DER generation would displace 1 MWh of RPS generation.

The existence of banking and curtailment complicates these relationships a little. There may still be some NPV CO2 savings even when DER receives Bucket 1 REC treatment due to timing, as DER generation can be installed during years when RPS generation is overprocured. In the other direction, DER may cause incremental curtailment, which would limit this incremental renewable generation during years with RPS overprocurement.

Also, note that the societal cost of carbon input should be incremental to the private cost of carbon.

53. When a user assumes Bucket 1 treatment for DER RECs, please specify the lines in the Revenue Requirements model where DER energy is subtracted from the RPS energy requirement.

These subtractions occur in rows 2034-2038.

Note that RPS needs are currently calculated based on usage net of DER. As noted below in Section 2, Revenue Requirement, Item #1, in the final version of the draft tool when DER counts for Bucket 1, cumulative DER energy will not be subtracted from usage prior to calculating RPS energy needs.

54. What commercial arrangement is being represented in the Public Tool's adoption module (i.e. PPA/lease, host-owned or other)?

The commercial arrangement modeled is a third-party owned system with a PPA agreement to a participating customer.

55. Are the DER Pro Forma inputs correctly labeled as "system costs" or should they be labeled "system price?"

The first inputs block on the DER pro forma tab refers to the system capital cost (i.e., the wording here is simplified to "system cost") and is correctly labeled. The DER capital cost ($/W) includes (a) the cost of equipment and labor and (b) profit. The cost of equipment and labor includes the actual equipment cost and installation labor, including administrative overhead and carrying costs. Profit includes the system integration premium to the solar provider for the risk it assumes installing the system and ensuring it functions to contractual specifications and general markup on system equipment components and the engineering and construction of the system. The system capital cost ("system cost") is the capital cost used to cost the lease price (DER LCOE).

The DER LCOE, or lease price, includes the system capital costs and operating costs including O&M, property taxes, insurance and an adequate return on invested capital. Return on invested capital (WACC) provides adequate compensation to any holder of lease capital for the risk it assumes during the operating period of the asset. The weighted average cost of capital (WACC) reflects the average credit quality of lessees, the interest rate environment, and the term of the lease. WACC can be decomposed into a wide range of capital structures including 100% debt or debt + tax equity. Note that equity return provides adequate compensation for holders of equity capital that bear higher risk than holders of debt. An example that may be helpful is a new car lease. The "system cost" of a new car is the cost of building the car, including any dealer and manufacturer profit. The price of a new car lease is related to the "system cost" of the car, the term of the lease and the credit quality of the lessee.

56. On the Advanced DER Inputs tab, is the DER Solar Price Forecast (based on LBNL 2014 Tracking the Sun report) representative of the vendor's transaction price with the end-use customer? Does LBNL specify in its report whether these prices already embed all financing costs and margins?

See response to #55 above.

The Tracking the Sun report states that its data consists of the upfront retail prices (i.e., capital costs) paid to project developers or installers. They exclude operations period finance costs and include margins above cost.

57. Does the DER Pro Forma tab add costs to the System Price input? If so, what costs? Which cell specifically represents the <u>price</u> to the end-use customer that is used to inform the customer decision to adopt?

We are unclear what you mean by the "System Price" input.

The DER LCOE is the price that informs the end-use customer's decision to adopt. It includes an adequate return of and on invested capital, O&M, insurance, property taxes, and inverter replacement.

58. The DER Pro Forma appears to start with the System Price and add a number project financing (e.g., DSCR) and operating costs (e.g., O&M), which reflects additional cash flows needed to capitalize and run a project and provide a return. Is it necessary to add these costs to the DER Solar Price Forecast if those prices reflect all-in prices, including financing, margins and O&M, of the vendor to the end-use customer?

Yes, it is necessary to include these costs. The capital costs do not include operating period costs.

59. If it is necessary to add financing and other costs, have these costs also been added to the historical prices (2008-2014) in calibrating the adoption module's sensitivity?

Yes.

60. If we wanted to test administratively set DER compensation rates, what is the best way to do that? For example, we want to test a Retail Rate Credit + Value Based Export Compensation scenario in which the export compensation is set to $0.15. Can we do this by setting the values in Cells E19 and E21:E28 in the "Basic Rate Inputs" Tab to "No," and then entering "$0.15" into Cell E30 in the "Basic Rate Inputs" Tab? Is there a way to test administratively set export compensation rates that are differentiated by TOU period (for example, $0.15 for off peak and $0.25 for on peak)?

Yes, that is exactly how you should test a flat administratively-set rate. Do not forget to include a nominal escalation rate as well.

No, there is not a way to set TOU value-based export compensation rates with differentials that are not tied to actual avoided utility system costs. We see no justification for time-differentiation that is not at least based on avoided costs. You can influence the time-differentiated value-based compensation by changing avoided cost inputs and by changing selection of the avoided cost components included in the compensation rate.

61. Is there currently a way to test a scenario that is Retail Rate Credit + Value Based Export Compensation, where the export compensation is set at the net surplus compensation rate defined in D. 11-06-016 (a simple rolling average of each utility's DLAP price from 7 a.m. to 5 p.m.)? Additionally, can we the tool to test this same scenario, but with a ratepayer funded subsidy provided to the participant up-front that is based on the EPBB methodology of the CSI program, and that is stepped down over the analytical time period assumed in the public tool?

There is not a way to explicitly test a Retail Rate Credit + Value Based Export Compensation scenario with export compensation at net surplus compensation. You can achieve a very similar rate by making the value-based export compensation include only time-differentiated energy avoided costs. The time differentiation will pick up the coincidence between PV and energy prices between 7 a.m. and 5 p.m. The energy prices would be at the CAISO level (not utility-specific DLAPs).

The Public Tool does include an option to model a ratepayer funded subsidy provided to the participant upfront that declines over time. Use the 'Utility Incentive (nominal $/W-AC)' inputs in cells X32:AC49 of the 'Advanced DER Inputs' tab. The Public Tool does not include logic to dynamically trigger subsidy reductions based on adoption level.

62. Is there currently a way to define a New DER rate in the Advanced Rate Inputs Tab that assumes a Baseline Credit (for example, F282 for PG&E) as well as Demand Differentiated Seasonal TOU (for example, E306:E309)?

No, there is not currently a way to do this. When we solicited stakeholder feedback on the rate designs that the Public Tool should be able to model, we did not receive any comments demonstrating interest in such a rate.

63. We are unable to determine what the difference is between the export rate vs. the delivered rate when selecting the different options (i.e., generation, transmission, distribution and other costs avoidable for all generation or only exports). For added transparency and to ensure ability to translate specific proposals, SDG&E is looking to identify where we would be able to find the values within the model. In addition, it is unclear what the rate structure is for the export only rate when choosing a different rate for export versus

delivered. For instance, under a tiered rate applied to delivered energy, is there ability in the model for an option to adjust the model to set exported generation at a flat or TOU rate?

We understand this concern and are looking into ways of presenting information on $/kWh compensation levels without substantially increasing model run time and complexity. Recall that value-based compensation levels may vary by rate territory, vintage, and time block. Snapshot values can be found on the 'Value-based Compensation' tab. Cost-based compensation levels may vary by technology and vintage. Snapshot values can be found in cell Y57 of the 'Bill Savings Calculator' tab.

64. There appears to be an error in the set of Peak Capacity Allocation Factors used in the Avoided Cost Calcs tab of the Public Tool. Here are the PCAFs for PG&E:

PCAFs by Rate Territory and TOU Period		PG&E					
Season	TOU Period	P,S	Q,T,Z	R	V,Y	W	X
Summer	6-9 AM	0	0	0.000081	0.000001	0.00013	0.000005
Summer	9-12 AM	0.000114	0.002103	0.006545	0.00206	0.010542	0.00208
Summer	12-2 PM	0.001282	0.006256	0.021646	0.009712	0.033069	0.006522
Summer	2-4 PM	0.02819	0.027737	0.05763	0.032485	0.073493	0.027001
Summer	4-6 PM	0.159258	0.100602	0.128122	0.116226	0.108679	0.109817
Summer	6-8 PM	0.142514	0.13382	0.094507	0.115765	0.070447	0.137265
Summer	8-10 PM	0.019072	0.062508	0.026498	0.042064	0.033138	0.050538
Summer	Overnight	0.000706	0.003588	0.007077	0.003084	0.010946	0.00356
Summer	Weekend	0.273015	0.389177	0.410623	0.405991	0.479367	0.400379
Winter	6-9 AM	0.000394	0.007228	0.000435	0.006688	0.000794	0.005646
Winter	9-12 AM	0.002669	0.028897	0.003004	0.025286	0.004735	0.02388
Winter	12-2 PM	0.000888	0.014187	0.001265	0.012179	0.002236	0.011523
Winter	2-4 PM	0.000234	0.002984	0.001934	0.002608	0.003079	0.002802
Winter	4-6 PM	0.009313	0.00195	0.004768	0.00277	0.002411	0.002824
Winter	6-8 PM	0.192855	0.069633	0.112865	0.094666	0.07019	0.088144
Winter	8-10 PM	0.034336	0.010723	0.028847	0.024832	0.023026	0.014663
Winter	Overnight	0.000134	0	0.001574	0.000563	0.00226	0.000103
Winter	Weekend	0.135026	0.138607	0.092579	0.103021	0.071459	0.113246

Note that by far the highest PCAFs occur on Summer Weekends (yellow highlighted line). PCAFs are based on the highest load hours. It does not seem at all logical that such a high percentage of high load hours occurs on Summer Weekends. Perhaps there is an error here in the order in which the PCAFs are listed?

There was a chronology year error that caused weekend PCAFs to be overestimated. The chronology year originally used to create hourly PCAFs differed from the one used to translate the hourly data into TOU periods. This will be corrected in the Final Tool.

65. Similarly, the highest line loss values in the Avoided Cost Calcs tab for PG&E and SCE are for TOU-9, which seems to be the Summer and Winter Weekend periods. Shouldn't the highest losses be on weekday afternoons or evenings?

		Average Electricity System Loss Factors			
Season	TOU Period	PG&E	SCE	SDG&E	Active
Summer	TOU1	1.011	1.059	1.051	**1.059**
Summer	TOU2	1.013	1.061	1.055	**1.061**
Summer	TOU3	1.019	1.064	1.056	**1.064**
Summer	TOU4	1.035	1.069	1.058	**1.069**
Summer	TOU5	1.035	1.070	1.058	**1.070**
Summer	TOU6	1.036	1.070	1.058	**1.070**
Summer	TOU7	1.019	1.066	1.056	**1.066**
Summer	TOU8	1.019	1.066	1.056	**1.066**
Summer	TOU9	1.044	1.094	1.051	**1.094**
Winter	TOU1	1.003	1.061	1.051	**1.061**
Winter	TOU2	1.013	1.062	1.054	**1.062**
Winter	TOU3	1.030	1.065	1.054	**1.065**
Winter	TOU4	1.029	1.065	1.054	**1.065**
Winter	TOU5	1.029	1.066	1.054	**1.066**
Winter	TOU6	1.030	1.066	1.055	**1.066**
Winter	TOU7	1.031	1.067	1.057	**1.067**
Winter	TOU8	1.018	1.064	1.054	**1.064**
Winter	TOU9	1.055	1.076	1.051	**1.076**

We are updating the loss factors used in avoided cost calculations to reflect the values used in the 2013 NEM study. These loss factors are provided in our response to question #68.

66. The last "Policy Input" on the "Key Driver Inputs" tab is the flag to choose whether all NEM generation or NEM exports count as Bucket 1 RECs for RPS compliance. The comment on this cell says that "The option "All NEM Successor DER Gen Counts for Bucket 1" is ONLY compatible with a "Cost Based Compensation" or "Value Based Compensation" structure as defined in the Basic Rate Inputs tab." Is this true? Why is Bucket 1 treatment only compatible with these two options? When Bucket 1 REC treatment is selected for all NEM output, the avoided cost results change even if NEM Successor Tariff compensation stays at the Full Retail Rate in the Basic Rate Inputs. This appears to contradict what is said in the comment. Please clarify how this works.

The compatibility constraint is a political constraint, not a logic constraint. While the model will allow users to select 'All NEM Successor DER Gen Counts for Bucket 1" with all NEM successor structure options, the CPUC will not consider any proposals that award Bucket 1 RPS credit for generation credited at the full retail rate.

67. For PG&E, distribution marginal costs are specified by customer baseline territory. In the prior model, and in GRCs, PG&E presents marginal distribution costs by division. How did E3 convert the PG&E marginal distribution cost inputs from divisions to baseline territories?

While the E3 NEM Avoided Cost Model only presents marginal distribution costs by division, the 2013 NEM analysis did calculate marginal distribution costs by baseline rate territory. This analysis uses the same climate zone to baseline rate territory map that was used in the 2013 NEM analysis:

Rate Territory	Climate Zone 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
P,S	0	0.0554	0.0019	0.0074	0	0	0	0	0	0	0.2796	0.5761	0	0	0	0.0796
Q,T	0.0826	0.0344	0.6411	0.0906	0.1022	0.0049	0	0	0	0	0	0.0442	0	0	0	0
R	0	0	0	0.049	0.005	0	0	0	0	0	0.1081	0.1822	0.4244	0	0	0.2312
V,Y	0.3873	0.2043	0	0	0	0.0052	0	0.0052	0	0	0.0362	0.0414	0.0052	0	0	0.3154
W	0	0	0	0.091	0.015	0	0	0	0	0	0	0	0.682	0	0	0.212
X	0.0431	0.2144	0.2495	0.2705	0.0321	0.014	0	0	0	0	0.003	0.1303	0.0261	0	0	0.017
5,6	0	0	0	0	0.004	0.996	0	0	0	0	0	0	0	0	0	0
8	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0
9	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0
13	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0
14	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0
16	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
1	0	0	0.554	0	0	0.162	0	0.162	0	0.122	0	0	0	0	0	0
2	0	0	0	0	0	0	0	0	0	0.1878	0	0	0	0.5624	0.2498	0
3	0	0	0	0	0	0	0	0	0	0	0	0	0	0.5	0.5	0
4	0	0	0	0	0	0	0.013	0.392	0	0.481	0	0	0	0.114	0	0

68. Please confirm that the model uses average line losses for avoided costs in the Avoided Cost Calc tab (Lines 185-204). Are these transmission losses, distribution losses, or combined transmission & distribution losses?

We are updating the loss factors with those used in the 2013 NEM Study. These are provided below.

TOU	Description	PG&E	SCE	SDG&E
1	Summer Peak	1.109	1.084	1.081
2	Summer Shoulder	1.073	1.080	1.077
3	Summer Off-Peak	1.057	1.073	1.068
4	Winter Peak	-	-	1.083
5	Winter Shoulder	1.090	1.077	1.076
6	Winter Off-Peak	1.061	1.070	1.068

69. At the end of each annual billing period for a NEM customer, the customer loses any remaining balance in unused NEM credits. This loss of unused bill credits reduces the lost revenues for the utility. Does the model capture these end-of- year bill credits that are zeroed out?

Yes, the Public Tool captures this zeroing out of end-of-year bill credits under full NEM compensation. If the user does not input a minimum bill for any given rate structure, the Public Tool sets an annual minimum bill of zero. This does not hold under cost-based compensation, value-based compensation, or asymmetrical compensation. Note that the Public Tool does not allow any customer to install a DER system that generates more than 100% of the customer's usage, so there is no surplus generation.

70. Does the California Climate dividend play a role in the determination of future rates and revenue requirements? For example, if High GHG allowance prices are chosen, does this increase the future climate dividends, compared to Base GHG prices, and are these higher dividends assumed to reduce future rates used in the model?

Yes, the Climate Dividend changes with GHG allowance price assumptions. The Climate Dividends flows into rate calculations via a revenue requirement credit for residential and small commercial customers.

71. The model calculates future renewable curtailments in the 40% and 50% RPS scenarios. Could the model assume that this curtailed RPS generation could be sold out-of-state at a market price?

The model uses the curtailment logic in the RPS Calculator version 6.0. While it may be possible to sell excess generation out-of-state in certain hours, it is not assumed to be sold out-of-state in this model.

72. Based on our review of the Revenue Requirement model, the PT appears to treat the PCIA as a non-bypassable cost of NEM for bundled customers as well as for DA/CCA customers. Is this true, and if so, please justify this treatment given that bundled customers do not pay the PCIA?

In the Final Tool, calculations were changed to include bundled energy costs in the bundled revenue requirement.

73. The PT has just one TOU period for weekends. Hourly energy market prices are higher during weekend daylight hours and on weekend afternoons than on average across all weekend hours. Did E3 evaluate whether this results in a material understatement of avoided energy costs?

E3 did evaluate whether the added tool complexity necessary to incorporate weekend price variability would have a material impact on avoided energy costs. Specifically, E3 used 2012 CAISO NP-15 day-ahead prices with a representative DER solar shape, and found that averaging weekend prices undervalued 2012 avoided energy costs by less than 2%. Note that as more solar is installed within the CAISO market (both behind-the-meter and utility-scale RPS), energy prices during hours of solar output will decrease.

74. We ran a case using a full retail rate credit, but with "Other" costs specified as Non-Avoidable on the Basic Rate Inputs tab (cell E66 and subsequent similar cells). We did not

specify what those Non-Avoidable "Other" costs were on the Advanced Rate Inputs tab (we left those cells blank), but still saw a significant decrease in NEM costs in the results.

a. If Non-Avoidable "Other" costs are not specified on the Advanced Rate Inputs tab, does the PT assume all such "Other" costs are Non-Avoidable?

b. Where can we see what the PT is calculating & using for Non-Avoidable "Other" costs if they are not specified on the Advanced Rate Inputs tab?

c. Finally, in this run the results changed significantly for systems installed in 2008-2016, even though cell J55 on the Basic Rate Inputs tab says that the choices of certain Non-Avoidable rate components "only apply to participants that install DER in 2017 or later." This statement does not seem to be true, based on our run. Please clarify.

Non-bypassable charge levels are calculated by the model and cannot be specified by the user. Users may only specify whether DER can avoid all or a portion of these non-bypassable charges (i.e., exports non-avoidable selection). The cell that this user left blank is not a cell in which to input a value but rather a dropdown which can override the default assumption from the basic rate inputs tab.

The level of the non-bypassable charges calculated by the model can be found in rows 267-275 of the 'RR' tab. The only active non-bypassable charge category in the model is the "other" category: the generation-, transmission-, and distribution-related non-bypassable charge components have all been included in the "other" category.

Note that the non-bypassable treatment selection applied to all participants irrespective of what year they install DER (pre 2017 or post 2017). The most recent version of the Public Tool includes a correction for this error.

75. When the ED scenario assumptions are pasted into the Scenario Tab of the Public Tool, in order for the Tool to run correctly should they be pasted in as values?

Yes, they should be pasted as values. However, all of the saved scenarios in the ED scenario assumptions workbook (they start in column F) are saved as values to this should not be an issue.

76. It appears as if the method used on the RR Calculation tab double counts Diablo Canyon capital expenditures as they are included in the general generation capex numbers entered in L250:N250 and then added in the years the plant is operating. If the generation capex numbers from the GRC are used going forward and an adjustment is made for the retirement of Diablo Canyon the Diablo Canyon capital costs should be removed from the forward stream of capital expenditures post 2024.

Thank you for letting us know about this error. It has been corrected in the Final Tool version posted online 6/17/2015.

77. The file PublicToolInputScenariosforStaffPaper.xlsx shows input data from rows 6 to 3181 (as does the "Scenario" tab of the latest version of the uploaded tool, Public Tool.xlsm), but the files that were uploaded for the Public Tool Model Runs of Scenarios from Staff Paper show input data from rows 6 to 3191. In other words, the model runs contain 10 more rows of input than the uploaded Public Tool and Input Scenarios.

Changes were made to the model between the Staff Paper runs and release of the Final Tool. It is correct that there are 10 fewer rows in the Final Tool. The Staff Paper scenario results were provided for information only. Users should not be attempting to use this data to run scenarios in the Final Tool.

78. Cell C18 in the "Key Driver Inputs" tab is the "Marginal Avoided Subtransmission Cost Multiplier." This multiplier should apply to the Marginal Avoided Subtransmission Costs for all three IOUs (cells D327:D329) in the "Avoided Cost Calcs." However, in these cells, only the cell for PG&E (cell D327) refers to C18 in the "Key Driver Inputs" tab. The other two cells, for SCE and SDG&E, refer to the lines below C18 in the "Key Driver Inputs" tab (C19 and C20), and thus fail to apply the Marginal Avoided Subtransmission Cost Multiplier correctly to SCE and SDG&E.

Thank you for bringing this error to our attention. The active SCE marginal avoided subtransmission cost was referencing the marginal distribution avoided cost multiplier. This error impacts SCE subtransmission avoided costs when the marginal subtransmission avoided cost multiplier input differs from the marginal distribution avoided cost input. This error has been corrected in the version of the Public Tool posted 6/17/2015. Note that SDG&E does not have marginal subtransmission costs.

79. The "Pub to RR" tab at cells AU660:AU1344 multiplies transmission avoided cost by (1+inflation)^(active year - 2011). However, transmission avoided cost is the product of (kW adoptions) x (ELCC) x (2015 $ per kW), where the transmission price is in 2015 dollars (see cell C16 of the Key Driver Inputs). This seems wrong, as 2015 should be in the exponent rather than 2011, or the transmission price should be expressed in 2011 $/kW. There does not appear to be a similar problem for subtransmission (AI660:AI1344) and distribution (X660:X1344) avoided costs, since those inputs on the Avoided Cost Calcs tab (E327:E350) are in 2011 $/kW-yr.

Thank you for bringing this dollar year inconsistency to our attention. We have corrected the dollar year used in the marginal transmission avoided cost calculations on the 'Avoided Cost Calcs' and 'Pub to RR' tabs. The Public Tool posted 6/17/2015 includes this correction.

80. How did E3 determine SCE's distribution cap ex? In the June 4 Public Tool Documentation, the answer question 28b cites "data from SCE's 2015 GRC, SCE-10, Vol. 02, Tables I-1, II-7 and II-8, which will result in starting average annual distribution capex of $1.96 billion per year." The referenced tables show depreciation expenses and not cap ex. A similar explanation would be appreciated for the generation cap ex.

Table I-1 shows the breakdown of plant in service for each year. The capex figures are determined by subtracting the previous year's value from the current year's. For example, the 2013 generation capex of $383 million equals $10,841 less $10,458.

81. The June 4 Public Tool Documentation says for SDG&E cap ex that "E3 used the 2016 GRC Direct Testimony of Jesse S. Aragon, Table SDGE-JSA-2." (I think they mean JSA-3, not JSA-2.) I can derive the numbers in the model form that table, but why did E3 use the total cap ex plus an assumed 40/60 split based on the total capital expenses in JSA-3 rather than the capital expenses explicitly broken down between generation and distribution (presented in SDG&E-9 and SDG&E-11)? When you look at the testimonies explicitly presenting the generation and distribution capexes, you can see that the generation is actually much smaller than shown in the model while the distribution is bigger.

The sum of cap ex in SDG&E-11 and SDG&E-9 is not equal to the difference between annual fixed capital amounts shown in Table SDGE JSA-2. Due to this discrepancy, E3 developed an alternative forecast.

82. Where did the SCE and SDG&E O&M and A&G values come from?

E3 developed these values from O&M-related testimony from SDG&E's 2016 GRC, Appendix C of SCE's 2012 GRC, and the PUC Section 747 Report.

83. Looking at PG&E, it appears that adjustments to the generation O&M would also need to be made to account for the retirement of Diablo Canyon described in question 76 above.

E3 did not make this adjustment because we assume that some level of O&M costs will continue after nuclear plant retirement.

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84. In the RRQ model on the RR Calculation tab, there appears to be an error in row 4046 (part of the calculation of avoided RPS value). The cell is supposed to represent the capacity value of RPS resources in $/MWh. If you look at the formula, it's taking the $/kW-yr "active capacity cost forecast" from row 4032 and multiplying by the weighted ELCC in 4044. This $/kW-yr value should be translated to $/MWh by multiplying by some kind of weighted capacity factor, which would lead to a lower capacity value. By overestimating the capacity value, the above market cost for RPS resources is underestimated (and therefore the REC value is underestimated).

Thank you for bringing this issue to our attention. The correction is as follows:

- In cell J2412, type = SUM(J2410, J2398, J2386, J2374) and fill across through column AV
- In cell J4045, type =SUM(J3422:J3439)*1000/SUM(SUM(J3281:J3306)/1000, J2412)/8760 and fill across through column AV.
- In cell J4046, type =J4044*J4032/J4045/8.76 and fill across through column AV.

85. For SDG&E, while the DDMSF function was fixed for the corrected units, the distribution of bills in the 3 kW buckets appears to be much higher than SDG&E data has shown. The public tool shows 43% of bills above 6kW, whereas SDG&E data has shown only about 10% of bill have demands over 6kW and more than 50% are less than 3kW, versus the public tool showing just 16%. This distribution also has the potential to impact the demand determinants for the calculation of a demand charge.

Thank you for bringing this issue to our attention. We have recalculated these billing determinants using the load research data and the customer bin weights. Our updated estimates show 48% of SDG&E residential customer-months with peak demand less than 3 kW, 37% with peak demand between 3 and 6 kW, and 15% with peak demand greater than 6 kW. If SDG&E has more precise numbers that it would like to provide, we would be happy to incorporate them.

To update the model with the re-calculated billing determinants, paste the following values into the specified cells on the 'RR Calculations' tab in the revenue requirement model:

- Cells I9065:I9070

0.2404793
0.2572994
0.1489432
0.1710736
0.1105775
0.0716270

- Cells I9534:I9539

0.1132836
0.2914858
0.1130968
0.2598475
0.1069530
0.1153334

- Cells I10003:I10008

0.2325954
0.2494110
0.1670685
0.2044223
0.1003360
0.0461667

Note that this change will only impact model cases that involve the Demand Differentiated Seasonal Time-of-Use rate.

86. The pre-populated default rates for non-residential do not match with the current effective rates or structures of SDG&E non-residential rates. One specific example is the medium and large commercial showing a $20 winter demand charge and $7 summer demand charge, whereas SDG&E's non-coincident demand charge is the same in the summer and winter. This is concerning because the ALJ ruling says that the user cannot change the default rate from what is pre-populated.

To update the model with default rates that better match current effective non-residential rates for SDG&E, paste the following values into the specified cells on the 'Advanced Rate Inputs' tab in the public tool.

Cell	Value
F1667	Seasonal Time-of-Use
F1673	12
F1677	0.2089
F1678	0.27691
F1684	12
F1691	0.210395
F1692	0.23437
F1693	0.23725
F1694	0.27691
F1695	0.31955
F1782	116
F1784	24.43
F1785	24.43
F1788	21.4
F1789	0.086185
F1790	0.11283
F1791	0.08369
F1792	0.11485
F1793	0.12471
F1869	465.74
F1871	24.43
F1872	24.43
F1875	21.4
F1876	0.086185

Cell	Value
F1877	0.11283
F1878	0.08369
F1879	0.11485
F1880	0.12471
F1936	465.74
F1938	24.43
F1939	24.43
F1942	21.4
F1943	0.086185
F1944	0.11283
F1945	0.08369
F1946	0.11485
F1947	0.12471
F1997	Seasonal Time-of-Use
F2003	18.23
F2005	0
F2006	0
F2007	0.14872
F2008	0.18666
F2014	18.23
F2015	0
F2016	0
F2017	0
F2018	0
F2019	0
F2020	0
F2021	0.124835
F2022	0.14209
F2023	0.18838
F2024	0.23742
F2025	0.28361

87. SDG&E historical adoption (through 2014) was not calibrated to actual observed adoption. The following table shows the change from the draft tool to the final tool with a comparison to SDG&E's actual installed capacity, the total pre-2014 adoption is still 18% less than observed adoption. This is just slightly improved from the 21% less adoption shown in the draft tool.

			DRAFT TOOL - Submitted in Comments		FINAL TOOL		
	SDG&E Data	Public Tool	Variance (#)	Variance (%)	Public Tool	Variance (#)	Variance (%)
	Installed NEM kW	Installed NEM kW	Installed NEM kW	Installed NEM kW	Installed NEM kW	Installed NEM kW	Installed NEM kW
Pre-2009	43,824	32,269	-11,554	-26%	32,269	-11,554	-26%
2009	16,418	14,720	-1,698	-10%	14,720	-1,698	-10%
2010	26,793	17,130	-9,663	-36%	17,130	-9,663	-36%
2011	36,381	29,439	-6,942	-19%	29,439	-6,942	-19%
2012	40,168	29,998	-10,170	-25%	29,998	-10,170	-25%
2013	67,717	58,269	-9,448	-14%	61,543	-6,174	-9%
2014	105,055	82,391	-22,663	-22%	91,395	-13,659	-13%
TOTAL	336,355	264,217	-72,138	-21%	276,495	-59,860	-18%

There are three main factors causing this discrepancy:

1. Differences in our target adoptions: It was very difficult to reconcile the historical adoption numbers in the public AB 327 Monthly Reports, the confidential NEM Report data sets we received from the IOUs during the 2013 CA NEM evaluation, and the updated 2014 Q4 confidential NEM report data sets. After an extensive comparison process, we compiled the following estimates:

	SDG&E Incremental PV NEM kW
Pre-2009	49,428
2009	20,748
2010	23,919
2011	46,708
2012	40,837
2013	63,468
2014	105,109

We would welcome a follow-up discussion to reconcile differences in these databases of historical adoption.

2. Adoptions through 2012: We had difficulty reconciling actual historical NEM customer data with class usage distributions and technical potential (i.e., there were instances where the installed NEM capacity of historical NEM customers in a representative customer bin exceeded the bin's technical potential). We ultimately prioritized class usage distributions and technical potential and, thereby, the accuracy of forecasted adoption. While the resulting total historical adoption through 2012 in the Public Tool is still within 0.5% of actual historical adoption, there are inaccuracies in historical adoption allocation across utilities (see table below).

3. 2013 and 2014 adoption: 2013 and 2014 historical adoption was calculated using the Public Tool adoption logic in order to allocate historical adoption to specific customer bins for these years. We only used actual historical 2013 and 2014 adoption to help calibrate the adoption curve parameters and for benchmarking. We prioritized benchmarking total adoption across the three IOUs. The resulting 2013 and 2014 adoption estimates are higher than historical for PG&E and SCE and lower than

historical for SDG&E. Total 2013 and 2014 adoption is within 1.5% of our estimates for actual historical adoption:

	Total Incremental PV NEM kW	
	Public Tool	Target Actual Historical
pre-2009	376,263	375,893
2009	123,807	124,564
2010	181,797	181,508
2011	302,235	304,321
2012	359,006	351,251
2013	510,024	486,239
2014	657,876	666,199
2015	811,676	801,994
2016	856,426	898,234

Inaccuracies in historical adoption allocation across utilities should have a limited effect on key results, as this proceeding is focused on NEM successor customers. While allocation of 2013 and 2014 historical adoption does impact NEM successor economics, it is *total* historical adoption that is of primary importance for NEM successor economics. Allocation negligibly impacts other costs (i.e., interconnection costs, energy prices, marginal ELCC). Moreover, actual historical adoption through 2012 is included in the starting billing determinants in the revenue requirements, so the Public Tool's estimates of historical adoption through 2012 do not affect revenue requirements.

88. The 2015 total revenues in the revenue model are roughly 10% lower than where SDG&E is today. This is the same for 2014. Specifically, the Grid Transmission revenues are roughly $150 million in the revenue model yet over $400 million for SDG&E. Following the logic, the transmission revenue requirement is figured on a state level and allocated to each utility, which makes one assume that all utilities have lower transmission revenue requirements in the public tool than actual.

The Public Tool calculates rates applicable to bundled customers. Specifically, transmission costs applicable to bundled customers equal the transmission access charge (TAC) times bundled usage. CAISO's 2015 TAC Rates document shows SDG&E's filed annual TRR equal to $495.7 million, with SDG&E's TAC amount equal to the 2015 TAC Rate of $9.42 per MWh times SDG&E gross load of 20,876 GWh, or $196.7 million. Similarly, the revenue requirements model calculates a 2015 TAC of $7.65 per kWh and bundled SDG&E usage of 17,921 GWh, yielding the 2015 bundled transmission revenue obligation of $137.1 million. We believe the small discrepancy is not material to overall bundled rate levels.

89. SDG&E is seeing different results in adoption rates for SDG&E when SDG&E is ran alone compared to when SDG&E is ran with all IOUs.

This result is expected. Many of the values in the model dynamically update with DER adoption. When the model is restricted to SDG&E, it assumes that there is no post-2016 adoption in PG&E and SCE service territories. The difference in results is the impact that this post-2016 PG&E and SCE adoption has on SDG&E DER economics (i.e., adoption, avoided costs).

90. How can we find cost shift values for residential customers, similar to the values in Table 48 for the 2013 CPUC NEM study?

Table 48 in the 2012 CPUC NEM study shows the aggregate bill payments above cost of service for NEM customers. This is distinct from the ratepayer impact.

We were not previously aware that parties were interested in this output metric for the NEM Successor Tariff proceeding. The Public Tool displays only the *percentage* recovery of cost of service for participants. To achieve the NPV magnitude of the over or under collection of cost of service recovery for residential participants, users could subtract the denominator of the equation in cell AS53 of the 'Results' tab from the numerator of the equation. Note that this output will still not be directly comparable to that of Table 48 in the 2013 study because 1) it includes CARE cross-subsidies in cost of service, and 2) it is an NPV number instead of a single-year (2011) number.

91. Do you have any new insights into how we can approximate a kW installed capacity fee that steps up in certain years between 2017 and 2025?

User-defined escalation factors applied to rate components and NEM successor charges are not within the scope of tool functionality. The user can select to run multiple cases with different levels of kW installed capacity fees (all cases being run from 2017-2025) and then only filter for the appropriate years in each case. While any aggregation/combination of these results would be missing many interactive effects and is not equivalent to individual case results, this approximation may provide sufficient information to inform analysis.

92. In both the 2 tier and 3 tier scenarios, does the public tool model shift to a default TOU schedule by 2019? If not, do you have any suggestions as to how the transition to default TOU rates can be represented using public tool results?

No, the tool does not shift to a default TOU schedule by 2019. Any transition to a default TOU schedule is not easily represented using Public Tool results. Similar to the question above, a user could run a 2 or 3 tier rate structure from 2017 – 2018 and then separate TOU case from 2017 – 2015, but any aggregation/combination of the results would be missing interactive effects and is not equivalent to individual case results.

93. In tab "Advanced Rate Inputs," cells E201 and F201, please help us understand when we would need the yellow cell (F201) to override the other one. We are confused, because the sidebar in the "Advanced Rate Inputs" sheet says "All grid charges and non-bypassable chartes must be specified here since they are not applicable to the default rate."

Cell E201 is a grid charge that is specified on the 'Basic Rate Inputs' tab, which links to all residential rate structures for all utilities. For example, one might override this value by inputting a value in F201 if he/she wished to specify a different grid charge value for PG&E as compared to the other utilities which would use the default value coming from the Basic Rate Inputs tab. Keep in mind that cell E201 and F201 would only be active if the user has also selected a 2 Tier inclining block rate design for the PG&E New DER Rate in cell F175.

The sidebar comment mentioned in the question is not making the distinction between inputs specified on the 'Basic Rate Inputs' versus 'Advanced Rate Inputs' tabs; it is pointing out that some rate components must be specified for the 'New DER Rate' even if the new DER rate design is set to 'Default' and those rate components have already been specified for the corresponding default rate.

94. Does cell G201 in "Advanced Rate Inputs" really ask for the annual kW nameplate value, rather than a monthly kW nameplate value?

Yes, this cell is asking for an annual value. Since bill savings are calculated on an annual basis, this is equivalent to entering a desired monthly kW nameplate multiplied by 12.

95. Does the Public Tool explicitly show what the average $/kWh value of the Export Compensation paid to DG customers is under a 'Retail Rate Credit + Value Based Export Compensation' structure? For example, if you select the above structure with exports paid at the toggled avoided costs and run the model, the 'Results' tab shows a Levelized Net Avoided Costs graph that includes all the avoided costs components, regardless of what was toggled 'Yes' or 'No'. Is the Export Compensation Rate simply the summation of the specific toggled avoided costs' value components shown in this graph?

You can find the levelized $/kWh value-based compensation levels by vintage, rate territory, and TOU period in cells AW159:BA183 of the 'Results' tab. If you filter out grandfathered vintages (cells D75:D83), you can find the resulting average levelized $/kWh export compensation payment in the stacked bar chart in cells F213:I236. The average compensation level should be roughly commensurate with the levelized net avoided costs if the compensation is time-differentiated and includes all of the avoided cost components and no societal adder ('Basic Rate Inputs' tab). Even under this scenario, the compensation and net avoided costs will not be exactly equal because 1) all generation and exported generation have different shapes, 2) the compensation does not include upfront program costs, and 3) the $/kWh capacity portion of compensation is approximated in order to be technology agnostic.

96. We would expect this Export Compensation Rate to be the same as the 'Customer Direct Compensation' portion (in light blue) of the levelized benefit shown in the PCT results (in $/kWh). However, this 'Customer Direct Compensation' number is usually much smaller than what we would interpret the Export Compensation Rate is (about half or so).

Make sure that you filter out grandfathered vintages when viewing this chart. The NEM successor tariff does not apply to grandfathered customers, so the exports of grandfathered systems are compensated under full NEM.

97. Why are the 'Customer Bill Savings' bar in the levelized results (shown in brown) not the same for the PCT and RIM cases?

The biggest difference between the levelized PCT bill savings and RIM bill savings is the assumed discount rate. These discount rates can be specified on the 'Key Driver Inputs' tab. The default participant nominal discount rate is 9%, while the default utility nominal discount rate is 7%.

The undiscounted values also differ somewhat because the PCT metric is customer bill savings, which takes into account the rate impact of adoption by other customers, while the RIM metric is utility lost revenue, which compares the rates with all DER to the rates without any NEM successor DER.

98. On the results tab in the "Detailed Rate Outputs" table, the volumetric energy rates do not appear to include non by-passable charges (NBCs), understating the level of rates in a given year. Either an NBC row should be added, or the NBCs added back to the various energy rates.

You are correct that the energy rates did not include NBCs. We added a NBC row to the "Detailed Rate Outputs" section in the final version of the Public Tool in response to this comment.

99. Per the response to question 74 in the public tool documentation, NBC treatment for DG applies to grandfathered customers, even if only selected for NEM successor tariff participants. Would it be possible to fix this such that this applies only to successor tariff participants? If not, could it be clarified why this is the case?

Yes, we have fixed this issue in the most recent version of the Public Tool.

100. A daylight savings adjustment inconsistency has been identified in the Avoided Cost Model used in the 2013 NEM Ratepayer Impacts Evaluation. Has this issue been corrected in the Public Tool?

This issue does not impact the Public Tool. The error manifests itself as a time shift in energy loss factors in the 2013 Avoided Cost Model. In the Public Tool, avoided losses are calculated dynamically by applying loss factors to TOU periods based on net delivered energy. The TOU period specifications are in Pacific Prevailing Time (PPT).

101. When the residential demand billing determinants were corrected for SDG&E, did E3 check that the other utilities did not have the same issue?

Yes, we identified that this issue applied across all three utilities. The response to question #85 includes updated billing determinants for PG&E and SCE.

102. The customer bill savings is generally higher in the PCT than the RIM. Is this due to the PCT using the "actual" rates and the RIM using the counterfactual rates with no post-2017 DG?

See response to question 97.

103. For a value-based feed-in tariff with only a societal adder (user-defined value), the detailed compensation outputs are higher than the user-defined input. Why does this occur?

The detailed compensation outputs are shown by vintage year, not calendar year. The values are levelized over the useful life of the NEM successor technology, incorporating the impacts of the user-defined societal value adder escalation. The user-defined input is the first-year value.

104. For the value-based feed-in tariff, what is the RPS adder and how does it change if DER counts towards RPS?

The RPS adder is the avoided above-market marginal cost of RPS energy, net of capacity benefits and integration costs. Whether DER counts towards RPS impacts the proportion of DER generation that displaces utility-scale RPS generation versus thermal generation. Displacing more RPS generation increases marginal avoided above-market RPS energy costs. If DER does not count towards RPS bucket 1 and RPS is not over-procured, 33%, 40% or 50% of the DER generation displaces RPS generation by reducing net load and, thereby, the RPS compliance obligation. If DER does count towards RPS and RPS is not over-procured, then 100% of the DER generation displaces utility-scale RPS generation. Note that banking impacts the actual percentage of marginally avoided generation that is from utility-scale RPS assets.

105. Is the nameplate capacity-based grid charge based on AC or DC kW?

The units are AC kW. We have re-labeled this input to make the units more clear.

106. We ran the tool with results for only one utility and the RIM result as a % of revenue requirement was small. What is the denominator for this metric when the tool in this instance?

The denominator in this calculation always includes the revenue requirements for all three utilities. The denominator is dynamic with DER vintage selections in the cost test result filters.

107. Will the Public Tool be modified to reflect the July 3, 2015 Decision on Residential Rate Reform – D.15-07-001?

The Public Tool inputs have been modified in response to the July 3, 2015 Decision on Residential Rate Reform, D.15-07-001, to allow parties to submit proposals that reflect the adopted rate structure as closely as possible within the current functionality of the Public Tool. The Decision instructs the three IOUs to file rate design applications that propose default TOU rates to be implemented in 2019. While the specific default TOU rate structures have yet to be established, we include two bookend TOU rates with baseline credits in the Public Tool saved scenarios. One TOU rate structure has a 2-8pm on peak period, while the other has a 4-8 pm on peak period. These TOU rate structures were designed to approximate TOU structures 6f and 6c, respectively, in supplemental filings by the IOUs filed in R.12-06-013 on April 8, 2015. Both TOU rate structures have on peak rates twice as large as off-peak rates, summer rates 25% higher than winter rates, and baseline credits that are roughly 20% of average rates.

We also include a two-tiered rate structure that reflects the consolidation and flattening of tiered rates without the introduction of TOU variation, as outlined in the Decision. The Public Tool will not model a third “Super-User Electric Surcharge” tier because significant adjustments to the Public Tool would be necessary in order to model this rate structure, and the time required to implement these adjustments would compromise the current proceeding schedule. Note that we assume that the TOU rates and non-TOU rates are all revenue neutral.

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108. We understand that the minimum bill mechanism described in the July 3, 2015 Proposed Decision on Residential Rate Reform is applicable only to delivery charges. If this is true, will the Public Tool perform the minimum bill calculation only on collections from delivery charges?

No, the Public Tool will only model a minimum bill that is applicable to total charges. While D.15-07-001 describes a minimum bill mechanism that is only applicable to delivery charges, properly modeling this mechanism is not within the scope of this project. E3 performed a separate analysis to better understand the impact of ignoring this nuance in the minimum bill application, and found that the magnitude of the impact is very small.

The current minimum bill logic will overestimate residential bill savings by less than 0.002%. Under the D.15-07-001 two-tiered rate structure, energy and delivery charges in the first tier are approximately equal (each composes ~50% of the total bundled rate). In any given month, customers will fall into one of three categories:

1. Customers with excess generation: These customers would be charged the stated minimum bill under a minimum bill that applies to only delivery charges and under the Public Tool logic.
2. Customers with variable charges between $0 and twice the stated minimum bill: These customers would pay more than the minimum bill amount if the minimum bill applies only to delivery charges. The Public Tool will slightly underestimate the bills for these customers. For example, if a customer’s variable charges are $10 (~$5 delivery + ~$5

generation), the customer would pay $10 under a minimum bill that applies to all charges and ~$15 under a minimum bill that applies only to delivery charges ($10 delivery + $5 generation).

3. Customers with bills at least twice as large as the stated minimum bill: The minimum bill would not apply to these customers. The Public Tool captures bills for these customers correctly.

The Public Tool only incorrectly calculates bills for customer-months in category #2. Based on the load and generation profiles of the residential representative customer bins used in the Public Tool and estimated adoptions under a full NEM tool run, E3 finds that about 20% of NEM participant customer-months fall into this second category. Under a $10 minimum bill, the magnitude of underestimation would be between $0 and ~$5 for each customer-month in category #2. Most Public Tool cases result in fewer than 4,000 residential NEM and NEM successor participants through 2025. Therefore, calculating the bill saving impact under conservative assumptions, we estimate an overestimation of annual bill savings by about:

$$(\$5/\text{customer month})\times(12\text{ customer months})\times(4{,}000\text{ residential participants})\\ \times(20\%\text{ of participants}) = \$48{,}000$$

On an NPV basis, this translates to about $730,000, which is less than 0.002**%** of residential participant bill savings.

These numbers also suggest that the bill savings from a $10 minimum bill applied only to delivery charges would collect about the same amount of revenue from NEM customers as a $10.50 minimum bill applied to total charges. Because the two numbers are so similar and because using a $10.50 minimum bill would cause participant economics to be less accurate for 80% of participants, we did not use this approximation method.

109. We ran a case of the current NEM structure that mirrored the Low DG value case, except that (i) 'More Daytime EV Charging' was selected in lieu of 'Less Daytime', and (ii) 'Base solar costs' were used in lieu of 'High costs'. We expected to see the results to fall in between the "bookend" cases, and while they did for some of the metrics, the case we modeled yielded significantly higher adoption than both Low DG and High DG Value cases. What explains this?

The "bookend" cases do not attain the minimum and maximum attainable adoption. The bookend cases were loosely defined to provide a reasonable range for the magnitude of the ratepayer impact. One of the largest drivers of adoption is the ZNE policy scenario. The Low DG value case includes a ZNE mandate, while the High DG case does not. This ZNE policy distinction is the main driver of adoption in your specified case being higher than adoption in the High DG value case.

110. The adoption impact of changing both the 'Electric Vehicle Charging Scenario' and the 'Solar Cost Case' key drivers together does not equal the sum of the adoption impacts of changing each of these drivers individually. What interactive effects drive this?

The main driver is likely the slope of the DER adoption curve. The electric vehicle charging profile impacts utility revenue requirements and, thereby, retail rates. Retail rates determine potential bill savings from DER adoption. The resulting change in expected participant benefits may have a small or large impact on adoption depending on how these benefits compare to DER system costs. For example, under low solar prices, the implied payback periods of investing in solar are likely very low, causing most customers to adopt solar if they are able to. A small increase in rates due to EV charging under this scenario will not have a large effect on adoption because most customers would adopt either way. In contrast, there may be a lot more customers who would adopt solar under a 7-year implied payback period than under an 8-year implied payback period, so a modest rate increase may have a large impact on adoption.

A much smaller driver may be that solar costs affect adoption, which changes the net system load shape. The net system load shape drives the marginal utility costs from increased EV charging in the middle of the day, so solar costs and EV charging have an interactive effect on rates.

111. We noticed that the cost of service recovery for residential customers (Cell AS53, Results tab) has unexpected results when comparing the Existing Policy and Bookend Case 2 Tiered High & Low scenarios. The existing policy cost of service recovery is 49%, but the same results for the 2 Tiered are 38% and 45% for low and high respectively. We would have expected the cost of service recovery to be higher for the 2 tiered cases. Why are we getting the results?

Percentage cost of service recovery of participants with DER is higher in the Existing Policy scenario than in the 2 Tiered scenarios because substantially more customer choose to install small systems in the Existing Policy scenario. Customers with smaller DER systems tend to have higher percentage cost of service recovery. The discrepancy in the size distributions is due to relative rate levels in the lower tiers. The rates for the first two tiers in the existing 4-tiered structure are generally lower than the first tier rate level in the 2-tiered structure. The large Existing Policy tier differential incentivizes more customers to focus on reducing net usage in the top two tiers and to limit system size beyond that.

Consistent with your intuition, looking at each of small, medium, and large systems individually, the percentage cost of service recovery is almost always higher in the 2-tiered cases than in the existing policy case. This shows that it is the size distribution that is driving the overall results.

112. In a comparison between scenarios with full NEM and asymmetric scenarios with exported generation compensated at avoided costs, SCE found some counterintuitive $/kWh levelized cost shift results. Moving away from full NEM and to the "Retail Rate Credit + Value Based Export Compensation" method of accounting for DER has either no impact on, or in many cases actually increases, the $/kWh levelized cost shift from DER for SCE C&I customers. This seems to imply that, over time, SCE's retail C&I rates are equal to or smaller than SCE's avoided costs as calculated by the Public Tool. What is driving these counterintuitive results?

In the aforementioned scenarios, the total magnitudes of the class-specific cost shifts (NPV $ and annualized $) are substantially higher in the full NEM scenarios than in the asymmetric scenarios. However, the levelized cost shift is higher for many classes in the asymmetric scenarios than in the full NEM scenarios because customers choose smaller systems in the asymmetric scenario. This is due to variable rates being much larger than the avoided costs during most times when the sun is shining. Because the C&I rates include demand charges, system size impacts levelized bill savings and, thereby, levelized cost shifts.

For example, the avoided costs are low enough that most medium commercial customers choose to size their DER systems to avoid exports in the asymmetric scenario. In contrast, the medium commercial variable rates in the full NEM scenario are large enough to incentivize installation of large systems, despite the demand charges. Under the default medium commercial rates, 85% of NEM successor systems are large (sized to usage) in the full NEM scenario, while only 2% are large systems in the asymmetric scenario. Levelized demand charge savings are typically larger for small DER systems than for large DER systems, as it becomes increasingly difficult for the marginal kWh of generation to reduce demand charges. On average, large systems, which are three times larger than small systems, reduce customer demand charges by only about 1.5x more than small systems. As a result, the levelized bill savings are higher for small systems than for large systems, causing the asymmetric scenario to have higher bill savings than the full NEM scenario.

113. In a comparison between scenarios with full NEM and asymmetric scenarios with exported generation compensated at avoided costs, SCE found some counterintuitive results concerning adoption and participant economics for SCE C&I customers. Moving away from full NEM and to the “Retail Rate Credit + Value Based Export Compensation” method of accounting for DER significantly increases the $/kW Net Participant Benefit, but this comes with much lower adoption. What is driving these counterintuitive results?

See the response to question #112. There are many more systems sized to load in the full NEM scenarios. Larger systems reduce the $/kW Net Participant Benefit due to diminishing marginal demand charge savings. Larger systems also explain the higher MW adoption result despite lower adoption in terms of number of systems.

114. SCE ran numbers with current rates and alternate underlying C&I rates that we would have thought would be more attractive to C&I participants than their current ones. SCE ran these rate structures under full NEM and asymmetric NEM successor tariffs. By going from current rates to DER-friendly rates, DER customers gain significant benefits in terms of $/kW net participant benefit. However, the forecasted adoption from the Public Tool doesn’t seem to reflect this increased benefit. Why does the Public Tool not estimate a higher increase in adoption?

The adoption curve and the technical potential determine how big an impact changes in participant economics have on adoption. For example, the implied payback periods for the medium commercial class in the specified scenarios are about 3.9 in the current rates and 3.1 in the solar-friendly alternate rates. Looking at the non-residential adoption curve on the 'Advanced DER Inputs' tab, switching to the alternate rate increases adoption from 80% of technical potential (22% of all customers) to 87% of technical potential (23% of all customers). This is about a 2.3% increase in adoption. The results from the alternate rate medium commercial scenarios described show 0.7% and 6.1% MW adoption increases, which are not too far from 2.3%. The departures from 2.3% are primarily due to changes in the DER size distribution. In the full NEM case, more small (33% of usage) systems are adopted in the solar-friendly rate scenario because many customers benefit greatly from just switching to a rate with lower demand charges, irrespective of DER generation. In the asymmetric case, while there are still a lot of small systems under rate R, the introduction of lower export compensation reduces system sizes more under rate B because it has lower variable rates.

115. E3 mentioned that the Public Tool might produce extreme results that do not reflect reality for SCE industrial, large commercial, and agricultural customer classes, as there are only 1-2 representative customers for each of those classes. Can E3 elaborate on this comment?

The Public Tool models the adoption decisions and economics of all California IOU bundled customers by using 685 representative customer bins. The bins can be thought of as a sample of the IOU customer population. E3 created these bins using data on historical NEM participants, and E3 used supplemental utility data to correct for size-related historical bias in NEM adopters. While no individual customer bin can perfectly represent an entire customer class, many customer bins considered together can create a good sample of the customer class population. Unfortunately, some utility-specific customer classes are missing or scarcely represented in the historical data set because few customers in those classes adopted NEM during the data timeframe. These customer classes are represented by only one or two customer bins in the Public Tool, so they are more likely to suffer from small sample bias (i.e., not be very representative of the customer class population). For this reason, E3 recommends using caution when interpreting results for SCE industrial, large commercial, and agricultural classes and for SDG&E large commercial and agricultural classes.

116. Why do residential MW adoption and percentage cost of service recovery decrease when a $24/kW-yr nameplate grid charge is added to the DER Low Bookend 2-tiered case (published date 06172015)? These results are counterintuitive.

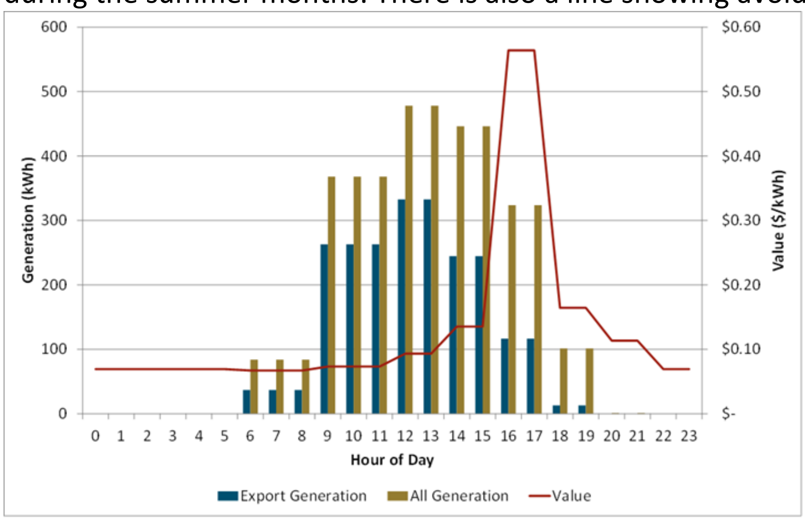
These counterintuitive results are driven by system sizing incentives. Adding the $24 grid charge reduces the number of DER systems adopted, but it simultaneously encourages participants to install larger DER systems. The grid charge essentially reduces the negative impact of the minimum bill because it brings total charges above or closer to the minimum bill. In the case described here with a $24 grid charge, 74% of all systems are large. In the case without a grid charge, only 48% of all systems are large. The larger system sizes cause the total MW adoption to be higher in the case with the $24 grid charge. Larger system sizes also reduce the numerator of percentage cost of service recovery.

Note that the addition of a grid charge only has this impact on sizing for classes with minimum bills.

117. Many runs testing existing NEM, including ED Staff Paper runs, show a worse (lower) export-only benefit/cost ratio than the ratio for all generation. Why is this the case?

There are two main drivers of the export RIM benefit/cost ratio being worse than the all generation RIM benefit/cost ratio:

- Avoided cost values are more highly correlated with generation consumed behind the meter than with exports. Most of the exported energy tends to be in the early/middle part of the day while most of the avoided cost value tends to be in the afternoon/evening. Therefore, the weighted average $/kWh avoided cost of energy is higher in the all generation case than in the export-only case. See the chart below of a sample PG&E residential customer's hourly total generation and exported generation during the summer months. There is also a line showing avoided cost value.



- Non-residential TOU rates generally have on-peak periods in the middle of the day, when exports are most common. This causes the weighted average variable rate for non-residential customers to be larger for exports than for all generation.

The export RIM benefit/cost ratio is also unintentionally biased downwards due to modeling logic choices and inaccuracies, which do not reflect real-world relationships:

- Under TOU rates with baseline credits and full retail rate credit successor tariffs, there is an error in the export-only baseline credit billing determinants that cause an 8-15% overestimation of the export-only RIM in the affected Staff Proposal cases. See FAQ item #120 for a full explanation of the error.

- Estimating export-only results with a level of precision comparable to all generation results was outside of the scope of this project. There are simplifications E3 made that add a slight upward bias to the export bill savings.

It is clear that the export RIM benefit/cost ratio would be lower than the all generation RIM benefit/cost for non-residential customers even if one corrected for the modeling logic biases. The relative export and all generation RIM benefit/cost ratios for residential customers are within the Tool's margin of error.

Note that the export-only case does show less of a cost shift from a total $NPV perspective.

118. How does the model estimate DER production? In order to calculate an implied payback period, you need three things: 1) How much the system costs; 2) How much electricity the system will produce; and 3) How much the customer will save from the electricity produced. How does the Public Tool do the second of those?

Recall that the representative customer bins in the Public Tool are based on information from actual historical NEM customers and utility load research data. The customer data includes geographic location, DER technology, and DER system orientation.

As part of the 2013 NEM ratepayer impacts evaluation, E3 simulated electric output from historical NEM PV systems using customer data on geographic location, array size, and panel orientation coupled with irradiance data from Clean Power Research. E3 used actual metered data to calibrate the PV simulation. Similarly, E3 simulated wind output for customers with NEM wind systems using customer data on geographic location and hub height coupled with wind speed data from Clean Power Research, wind turbine power curves from the Wind Power Program, and the 1/7 power law, which relates wind speeds at different heights under neutral atmospheric stability. See Appendix A of the *2013 California Net Energy Metering Ratepayer Impacts Evaluation* report for more information on these simulations.

Every representative customer bin in the Public Tool is associated with a PV output shape and a wind output shape. For historical NEM customers without PV systems, E3 mapped the customer locations to the PV output shape from the closest geographic location available. For historical NEM customers without wind systems, E3 simulated additional turbine output shapes using customer geographic locations, 10-minute wind data from NREL's Western Wind Dataset, NREL's geospatial wind class zones, and representative power curves from Wind Power Program.

For biomass, biogas, and fuel cell systems, the Public Tool uses flat output shapes.

Maintaining the generation shapes and capacity factors, E3 scaled all DER output for each bin to 33%, 67%, and 100% of customer usage ("small", "medium", and" large" systems, respectively).

119. Regarding the relationship used to translate benefit-cost ratios to implied payback periods, Slide 11 from the December 2, 2014 workshop slides says: "This relationship is based on a cash flow with an upfront cost and constant annual benefits." What are the constant annual benefits and how are they calculated?

That statement refers to the relationship used to translate benefit-cost ratios to implied payback periods. Because the Public Tool assumes PPA (levelized) financing of DER system costs, the participant benefit-cost ratio is actually calculated from a stream of costs and benefits that may change over time. A simple payback period calculated from these costs and benefit streams would generally be zero or infinity. E3 decided to use the relationship described on slide 11 to allow for a spectrum of participant financial propositions. The Public Tool uses the actual participant benefit-cost ratio to calculate an upfront cost and a constant benefit stream that would create that same benefit-cost ratio. It then calculates a simple payback period from that upfront cost and benefit stream.

120. Please describe the error notification dated 7/30/15.

An error was discovered in the Public Tool that impacts the residential Export-Only Ratepayer Impact Results when the following combination of Compensation Structure and Rate Design is selected:

- Compensation Structure = Full Retail Rate Credit
- Rate Design = Seasonal Time-of-Use with Baseline Credit

The impact of the calculation error is limited only to the residential export-only ratepayer impact results for a scenario where the compensation structure is set to "Full Retail Rate Credit" and the rate design is set to "Seasonal Time-of-Use with Baseline Credit." It does not impact any of the All-Generation cost test results, adoption forecasts, cost of service calculations, avoided costs, rate forecasts, or any non-residential results, nor does it affect any of the export-only results under any other available compensation structure and rate design combination options in the Public Tool. Below is a description of the calculation error and the impact the error has on residential Export-Only ratepayer impact results where the compensation structure is "Full Retail Rate Credit" and the rate design is "Seasonal Time-of-Use with Baseline Credit."

The calculation error generates residential Export-Only results that over-estimate the impact on non-participating residential ratepayers by 8%-15% in the four affected scenarios in the Updated Tables from the Energy Division Staff Paper, issued in the July 29, 2015 Administrative Law Judge (ALJ) Ruling. The magnitude of the error's impact is connected to the baseline credit amount and varies with rate levels. The calculation error can be found in cell AM153 of the "Bill Savings Calculator" tab.

The table below, prepared by consultants at Staff's request, demonstrates the impact of the error on Export-Only ratepayer impact results for the applicable Scenarios from the Updated Tables from the Energy Division Staff Paper, issued in the July 29, 2015 ALJ Ruling.

Update (07/31/2015) to Table 12: Cost Impacts of NEM to Non-Participating Customers for Systems Installed 2017-2025 (RIM Export Only Case) -- in order to provide information about range of the calculation error in the Public Tool when a Full Retail Rate Compensation Structure and Seasonal Time-of-Use with Baseline Credit Rate Design is selected.

Renewable DG Case	Default Residential Rate with NEM Compensation Structure	Forecasted Installations 2017-2025 (MW)	Public Tool Results: Average Non-Participant Benefit/Cost Ratio	Correct Results: Average Non-Participant Benefit/Cost Ratio	Public Tool Results: Ratepayer Impact/Bill Increase (% of Total RR)	Correct Results: Ratepayer Impact/Bill Increase (% of Total RR)	Public Tool Results: Ratepayer Impact/Bill Increase (% of Res. RR)	Correct Results: Ratepayer Impact/Bill Increase (% of Res. RR)	Public Tool Results: Ratepayer Impact/Bill Increase (% of Non-Res. RR)	Correct Results: Ratepayer Impact/Bill Increase (% of Non-Res. RR)
Low	TOU 4-8 Peak 2:1 Differential	12,098	0.15	0.17	7.99%	6.89%	14.75%	12.48%	1.68%	N/A
Low	TOU 2-8 Peak 2:1 Differential	11,771	0.14	0.16	8.35%	7.34%	15.48%	13.40%	1.68%	N/A
High	TOU 4-8 Peak 2:1 Differential	15,622	0.38	0.41	5.90%	5.04%	10.01%	8.17%	2.31%	N/A
High	TOU 2-8 Peak 2:1 Differential	14,707	0.37	0.40	5.75%	5.06%	9.75%	8.27%	2.23%	N/A

121. What was original source for the following assumptions? The revenue requirement tool cites the RPS Calculator v6.0, but it's difficult to identify what the source beyond that.

a. CT and CCGT Cost

b. CT and CCGT Heat Rate

c. Gas CT Economic Life

d. Fossil Steam Capacity factor

The source of CT and CCGT capacity costs is E3 analysis. Because the economic life assumption must match the levelization term we used a 20-year economic life for the CT. Similarly, the CCGT cost reflects an assumed 30-year economic life. To calculate the gas CT and CCGT heat rates, E3 averaged new plant heat rate data on the Non-RPS Generators tab. We assumed the fossil steam capacity factor would be equivalent to that of a CT.

122. How do the default renewable integration cost assumptions within the model compare to the values generated by E3 in D. 14-11-042? Our understanding is that this estimate ($2.38/MWh at a 33% RPS) was only for variable component of the renewable integration cost adder, while the default input in the model ($6.40/MWh) includes fixed components.

These figures are sourced from E3 analysis of prior studies of integration costs.

123. What was E3's rationale for maintaining current deviations from EPMC in RRQ allocations, rather than maintaining settlement rate relationships?

The intent was to have the allocation changes between classes reflect the underlying changes in marginal cost responsibility, realizing that there are some class-specific deviations that are applied in settlements.

124. What was the rationale for having slightly different non-residential rates in the public tool compared to existing rates?

To simplify modeling, the customer segments in the Public Tool are aggregations across several customer classes. E3 seeded the model with rates that were representative of the many different rate schedules that may be represented by one customer segment in the Public Tool.

125. All of the solar parties changed the Marginal Avoided Subtransmission and Distribution Avoided Costs for SCE and SDG&E. Why were SCE and SDG&E's costs different from PG&E's?

The GRC marginal subtransmission and avoided costs are typically higher than the capital costs that are actually avoidable by load per customer reductions. E3 calculated the avoidable marginal $/kW-yr subtransmission and distribution cost values that are used in the Public Tool avoided cost calculations by analyzingGRC distribution capital budget plans and identifying which cost items were actually avoidable. The utilities use different methods to produce these marginal costs. For example, SDG&E's method regresses total distribution costs on load and can be thought of as more of an average cost than a marginal cost. PG&E's method is the most similar to the calculation of actual marginal avoidable costs.

126. What is the impact of selecting "Non-Avoidable" for "Non-Bypassable [Other]" (Row 189 on the Advanced Rate Inputs tab) versus "Avoidable"?

The way the tool is operating now the 'other' category is actually the only active non-bypassable charge. This was a result how we categorized costs. The impact of selecting 'non-avoidable' means that the participant would have to pay the non-bypassable charge on gross usage whereas otherwise it is paid on net usage, which could reduce NBC collections to zero if the system is sized to 100%.

127. Several parties changed the customer assumed retail rate escalation to 3% from the default 5% in their independent scenarios. What is the implication of changing this input?

The tool was calibrated using both the assumed 5% escalation rate along with the adoption parameters and any change to these inputs means that the user is implying a fundamental change in the relationship for how many customers might adopt solar for a given economic proposition. This assumption change is akin to reducing the adoption parameters (which were historically calibrated). The implication of changing this input from 5% to 3% is that the tool will forecast less adoptions which will in turn decrease the cost-shift. We could have calibrated the tool using an assumed utility rate increase of 3% annually, but then the adoption parameters would have been higher.

128. Regarding Columns L-O on the Adoption Output page, which are written out below

Annual Energy Production (undiscounted)	Annual Energy Production (discounted)	Annual Energy Production - Single System	Annual Gross Usage - Single System

a. **What is 'Annual Gross Usage – Single System'?**

b. **Indicate whether it is possible to calculate the amount of energy (a) consumed on site and (b) exported to the system with the field indicated above, and explain how, if so.**

c. **Please direct me to the correct method to make the consumption vs. export calculation.**

a. "Annual Gross Usage – Single System" is how much energy one representative customer uses over the course of a year with no DER system. "Annual Energy Production – Single System" is the quantity of energy one DER system produces that that customer installs. If the customer installs a large system, these two values will be equal. If a customer installs a medium system, production will be 67% of usage. And if the customer installs a small system, production will be 33% of usage. You will also notice that "Annual Energy Production – Single System" multiplied by column K, which is the total number of systems installed, equals column L.

b. Yes, this is possible. The annual exported energy for all customers that install in each year is found in column AK of the "Adoption Outputs" tab. The annual DER energy generated for those customers is found in column L. The amount of energy consumed on site (aka behind-the-meter) would therefore be column L minus column AK.

The values above are annual values. The 25 year discounted present value of all energy production and exported energy production is given in columns X and AL respectively. Depending on what you are trying to calculate, you may need to use the annual values or the 25 year discounted values.

c. See above.

Last Updated: *August 18, 2015*

Section Two: This section lists calculation, or labeling, errors that were identified in the draft version of the Public Tool.

<u>Public Tool</u>

1. **<u>Grid Charge Application</u>**
   Grid charges are currently being incorrectly applied to grandfathered customers. Grid charges should only apply to NEM successor customers that install DER in 2017 and later. This will impact cost test results for grandfathered systems when the user has implemented a grid charge. This will not have any effect on the adoption forecast. This issue will be corrected in the next release of the tool.

2. **<u>Grid Charge Units</u>**
   Units – the "Grid Charge nameplate DER capacity" and "Grid Charge standby charge" have units currently listed as $/kW nameplate. These charges are annual recurring charges and the units should read $/kW-yr.

3. **<u>Allocation of CARE discount</u>**
   The model currently allocates the cost of the CARE discount to residential customers. The discount should be allocated to all customers except streetlighting and CARE participants. This change will decrease residential rates and increase rates for other customer classes except streetlighting.

4. **<u>Total Renewable Generation Output</u>**
   The "Total Renewable Generation (2017-2050)" output currently includes generation from 2013 through 2050, and the baseline excludes post-2017 generation of grandfathered systems. The final version for the tool will restrict the output to post-2016 generation and will include post-2016 generation of grandfathered systems in the baseline.

5. **<u>DER LCOE</u>**
   The PV price input default values will be divided by an AC-DC derate factor of 0.85 to convert to AC.

6. **<u>Adoption Logic When Storage is Disabled</u>**
   The adoption logic currently prevents any adoption of PV or PV coupled with storage for representative customer bins when the technology with the best customer proposition is a disabled storage technology. This issue will be corrected in the next release of the tool. Advanced users may fix the formulas in the 'Adoption Module' tab in the interim:
   - Formula for cell H28 (to be copied through H51): *=IF(OR(AND(D28="Solar + Storage (Grid Benefits)",'Bill Dets'!$R$9=0),AND(D28="Solar + Storage (Demand Min)",'Bill Dets'!$R$10=0),AND(D28="Solar + Storage (TOU Arb)",'Bill Dets'!$R$11=0)),FALSE,F28/G28)*

- Formula for cell I28 (to be copied through I51): *=IF(OR(AND(D28="Solar + Storage (Grid Benefits)",'Bill Dets'!$R$9=0),AND(D28="Solar + Storage (Demand Min)",'Bill Dets'!$R$10=0),AND(D28="Solar + Storage (TOU Arb)",'Bill Dets'!$R$11=0)),FALSE,F28-G28)*
- Formula for cell J28 (to be copied through J51): *=IF(H28,1/(INDEX($G$56:$G$63,MATCH(D28,'Advanced DER Inputs'!$D$54:$D$61,0))*H28),0)*

7. CT Real Time Revenue Robustness

The real-time CT revenue was built under the assumption that the heat rate of a new CT is greater or equal to the average market heat rate. Under some inputs, this may not hold true, in which case the Public Tool will produce errors. This logic will be made more robust before the next release of the tool by replacing the formula in cell J3045 (to be copied through AV3045) in tab 'RR Calculations' of the Revenue Requirement model to: *=MATCH(MAX(1,J3044*1000/AVERAGE(Energy!GR5:GR16)),'CT Real Time Market'!$C4:$H4,1)*

8. Meter Costs

The flag specifying whether incremental meter costs are applicable had not been included in SCE and SDG&E distribution revenue requirement blocks. This had the effect of applying incremental meter costs in all NEM Alternative scenarios. This flag will be added for SCE and SDG&E. PG&E's incremental meter costs were modeled correctly.

9. Demand Charge

The cell in the rate calculator tab that referred to the monthly demand charge was incorrectly referring to a previously deleted cell. This error only affected residential demand charges for NEM successor participants and has been corrected in the final public tool version.

Revenue Requirement

1. DER Counts for Bucket 1 Renewable Portfolio Standard (RPS) Scenario

In the policy scenario where DER counts for Bucket 1 RPS, cumulative DER energy will be added to usage prior to calculating RPS energy needs. Currently, the model calculates RPS requirements in this scenario using loads net of DER. This change will increase RPS costs in this scenario.

2. Stack Energy Calculation

2012 cumulative PV DER nameplate capacity is entered in MW and should be kW. This change will reduce the amount of market energy procured and will reduce marginal heat rates.

3. Demand Differentiated Monthly Service Fee Billing Determinants

There is a units issue in the transfer of the demand differentiated monthly service fee class level billing determinants. Cells A181:A186, A647:A652, and A1109:A1114 in the 'RR to Pub' tab should be set to 1 instead of 1,000. This will allow the model to provide reasonable rates under 'Demand Differentiated Seasonal Time-of-Use' rate designs.

Section Three: This section lists the changes that were made to the draft version of the Public Tool in order to produce the final version of the Public Tool.

Changes that affect inputs:

1. Clarified that $/kW grid charges are applied on an annual basis. This input can be found on the 'Basic Rate Inputs' tab and the 'Advanced Rate Inputs' tab.

2. Updated default distributed PV prices: fixed AC-DC derate and dollar year, adjusted learning curve parameters, approximated margin separately for calculations, and added a low case. For the default 'high' and 'base' case PV prices, E3 started with 2013 LBNL TTS prices. E3 assumed 40% of that price was margin and 60% of that price was cost. The base case cost portion was declined via a learning rate of 23% used in conjunction with the IEA global forecast while the base case margin was decreased from 40% of total cost to 10% of total cost by 2025. The high case cost portion was declined via a learning rate of 15% with a margin reduction from 40% to 15% by 2025. The low case followed an exponential decline toward U.S. DOE Sunshot goals of $1.50/kW-DC ($2010) for residential and $1.25/kW-DC ($2010) for commercial by 2020.

   Sources:

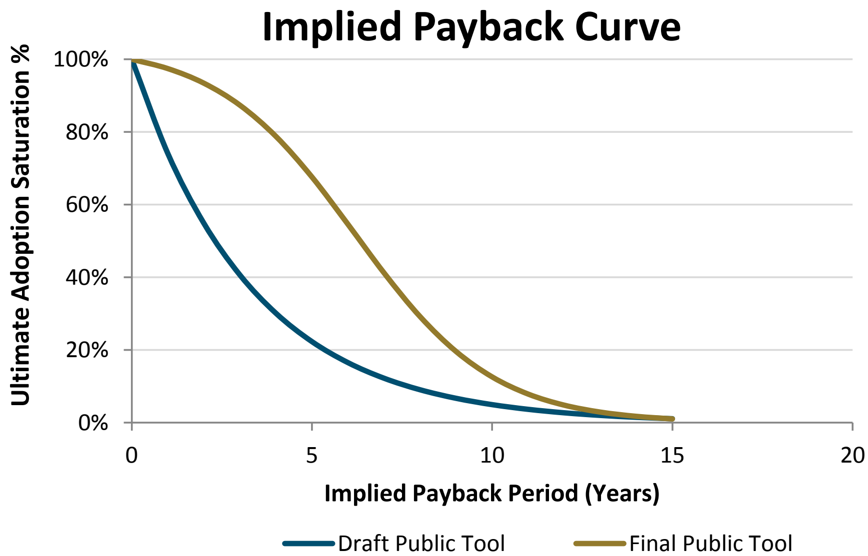
   http://emp.lbl.gov/sites/all/files/lbnl-6808e_0.pdf

   http://energy.gov/sites/prod/files/2014/01/f7/47927_chapter4.pdf

   http://www.iea.org/Textbase/npsum/MTrenew2013SUM.pdf

3. Added the feature of selecting utility-scale PV PPA cost trajectory (high, medium, or low) per DER PV cost trajectory. This selection occurs automatically with the DER PV selection.

4. Updated and recalibrated the adoption curve and adoption logic to produce more reasonable adoption outputs. The adoption curve used in the draft version of the public tool used an exponential function and the final version uses a logit function. For comparison, the two curves are shown below. The effect of this change was to increase the number of forecasted adoptions for a given economic proposition, especially for customers with good economic propositions.



5. Updated the residential DER technical potential inputs and calculations to account for different technical potentials across homeowners and renters. This involved increasing the default technical potential for residential customer-owned homes and decreasing the technical potential for residential rented homes. This change had a net effect of increasing residential adoption.

6. Replaced the old battery storage forecast with a high and low forecast. The forecasts assume exponential cost declines and were calibrated to public data sources, including reports released by Navigant, Rocky Mountain Institute, and the Brattle Group. The low forecast achieves Tesla's $350/kWh estimate in 2020 (Jaffe 2014). The 2014 high cost estimate is above $1,500/kWh. These inputs can be found on the 'Advanced DER Inputs' tab.

7. Updated default SGIP forecast inputs to reflect most recent 2014 values and incorporated a 10% annual price decline through 2025.

8. Added a multiplier to energy avoided costs to enable accounting for locational benefits. This multiplier affects avoided costs and value-based compensation, but it does not impact rates (except via bill savings under value-based compensation).

9. Changed the dollar year on the value-based FiT societal value input ('Basic Rates' tab) to match that of the rest of the inputs on the tab.

10. Added an input to enable overgeneration to be exported to neighboring states at a price of $0 instead of causing curtailment. Exported RPS generation receives RPS credit, while curtailed RPS generation loses its renewable quality and may need to be replaced with new RPS purchases. This input primarily impacts the RPS avoided cost adder, although it

also impacts the revenue requirement in multiple, counteracting ways. This input is on the 'Advanced DER Inputs' tab.

11. Hardcoded economic life of DER assets and storage replacement year. These are no longer user inputs. This was done for internal consistency within the tool given that parts of the tool structure rely on a 25 year life for solar. For example, the last year of forecasted solar adoption is in 2025, and the last year of revenue requirement forecast is in 2050.

12. Changed the description of the asymmetrical nonbypassable option (input) from 'Avoidable (exports only)' to 'Exports Non-avoidable (asymmetric)' because the previous description was misleading.

13. Removed the option to have a nonzero price for Bucket 3 RECs in the DER pro forma for simplicity.

14. Removed the option for cost-based compensation to vary by technology. This prevents modeling of unrealistic policy scenarios that cause technology selection to be arbitrary. Changed the default implied payback period for cost-based compensation to 7 years. This can be found on the 'Basic Rate Inputs' tab.

15. Deleted some unnecessary lines of inactive inputs in the 'Scenarios' tab.

16. Renamed the T&D avoided cost key driver inputs for clarification.

Other changes:

17. Allocated CARE discount costs across all customer classes (except streetlighting) and applied CARE discount via NBCs for non-residential accounts. CARE discount costs were previously fully collected from the residential class. The new logic reduces residential rates and increases rates in other classes versus results in the Draft Tool.

18. Reseeded forecasted adoptions from 2014-2016 with updated logic and inputs. The new seeded data reflects changes to adoption logic including the adoption curve, optimal sizing selections, and residential technical potential.

19. For DER size selection in the adoption logic, switched from using a highest NPV approach to a weighted average between NPV and B-C ratio approach. The draft version of the public tool used only NPV to select the optimal system size for a given participant, while the final version uses NPV and B/C ratio, which leads the model to select a larger percentage of small and medium systems. This decreases total MW adoptions and increases 'With DER' cost of service recovery because customers install smaller systems.

20. Added multipliers to energy storage benefits to capture energy arbitrage benefits lost with time granularity. The pre-processed storage dispatch is based on hourly avoided cost streams, but the calculation of benefits in the Public Tool is based on aggregated TOU periods. The new multipliers capture these lost arbitrage benefits within TOU periods and allow the benefits to be commensurate with the costs (variable O&M and efficiency losses). These multipliers were calculated by comparing the benefits of representative storage shapes under hourly avoided costs and the same avoided costs bucketed into TOU periods. These multipliers vary by rate territory and avoided cost component. They can be found on the 'Avoided Cost Calcs' tab.

21. For PV and PV+storage S curves, switched to using aggregate PV and PV+storage adoption to determine the appropriate point on the S curve at any given time. This limits the total technical potential of PV and PV+storage to that of PV. In many cases, it also accelerates storage adoption in the early years.

22. Stopped grid charges from applying to grandfathered customers.

23. Corrected total renewable generation output to restrict the output to post-2016 generation and include post-2016 generation of grandfathered systems in the baseline.

24. Corrected systems by size category output.

25. Clarified that the emissions output is a present value.

26. Corrected a bug in the adoption logic related to storage being disabled. Previously, this could prevent adoption of any DER. This will increase adoption in some cases.

27. Made CT real time revenue more robust. The previous logic caused errors when the heat rate of a new CT was lower than the average market heat rate.

28. Added logic to activate SCE and SDG&E incremental meter cost. These costs were previously calculated as if there were always new meters installed.

29. Changed utility-scale storage dispatch profile to incorporate curtailment. This helps reduce over-generation.

30. RPS compliance obligation corrected to be gross of applicable DER when DER counts for bucket 1 RECs. This change increases the RPS obligation basis in this scenario.

31. Changes units on 2012 DER capacity that flows into the energy stack calculations. This change increases the amount of DER flowing into the energy stack calculation.

32. Replaced average loss factors with marginal loss factors in the avoided cost calculations. These assumptions can be found in the 'Avoided Cost Calcs' tab. This change increases avoided losses.

33. Made loss factors by the 18 Public Tool TOU periods dynamic with delivered system loads. The loss factor values by load category (on, off, and mid peak) remain constant, but the TOU periods that are considered on, off, and mid peak may vary. This allows the coincidence between DER and losses to change over time and across cases to reflect system conditions, such as historical DER adoption and EV charging.

34. Corrected the chronology year used to calculate distribution PCAFs. This change impacts the subtransmission and distribution avoided costs via DER's coincidence with substation loads.

35. Updated the distribution component of the net cost of service calculation to be fully based on gross demand and the subtransmission component to be fully based on net demand. Previously, the allocation of these costs to classes was based on gross demand, and the allocation of costs to individual participants was based on net demand.

36. Moved bundled PCIA into energy charge and out of nonbypassable charges. This change reduces bundled NBCs and commensurately increases bundled energy costs.

37. Applied renewable integration charge to intermittent renewables only. This change reduces the revenue requirement.

38. Escalated generation and distribution O&M costs per input value. This change reduces the revenue requirement.

39. Corrected a units issue on demand differentiated seasonal TOU rate billing determinants to properly calculate demand service revenues.

40. Corrected references to gross class billing determinants on the 'RR' tab, and adjusted TOU maximum demand calculations to sum properly.

41. Made rate and revenue calculations on the 'RR' tab uniformly include DER through 2016 (baseline) or DER through the prior year.

42. Corrected the reference to SDG&E DER in the balance of CAISO system DER that feeds into the RR stack model.

43. Updated SCE distribution and generation gross plant, accumulated depreciation, and depreciation. This change reduces the SCE revenue requirement.

44. Corrected delivery usage by class in 2014 to conform to pre-processed figures.

45. Corrected coincident and weighted average system peak demand by class to include reductions for DER in cost allocation calculations.

46. Refined treatment of bundled and unbundled sales in 'RevAlloc' tab. This was mostly done for presentation purposes.
47. Disaggregated subtransmission (“primary”) and distribution cost components to the revenue requirement allocation summary. These cost components were previously reported in aggregation as distribution. This change does not directly impact results, but it allows cost of service to be based on net usage for subtransmission and gross usage for distribution.

48. Aggregated all streetlighting revenue requirement components in the 'RR to Pub' tab. This change does not impact results.

49. Changed PG&E bundled account growth rate to 1.24% from 1.9%. This change decreases the customer billing determinants.

50. Corrected balance of system RPS energy supply surplus (deficit) to reference RPS needs net of bucket 1 DER.

51. Corrected the RPS target reference in the 'RR to Pub' tab and added historical values.

52. Corrected the integration cost calculation to be based on actual RPS generation instead of RPS needs. This increases integration costs during periods when utilities are over-procured.

53. Corrected nuclear fuel costs to remain in the revenue requirement when Diablo does not retire. This change increases the revenue requirement for PG&E.

54. Corrected SDG&E gross class billing determinants to include EV usage. SDG&E EV usage was previously incorrectly excluded. This change decreases SDG&E rates.

55. Adjusted the RPS banking logic in the Public Tool avoided cost calculation to allow withdrawal of 10% of the credits that were banked during the first year of withdrawal instead of 10% of the credits in the bank in the active year. This change was made to align with existing policy.

56. For the lost revenue calculations chart, made 'Gross Bills: New Tariffs, No DER' equal to that of the default tariffs when all customers are on default tariffs to limit confusion.

57. Added nonbypassable charges to the average rate output charts.

58. Added summary output tables to the 'Results' tab.

59. Added detailed outputs on value- and cost-based compensation to the 'Results' tab.

60. Added more documentation and explanations within the models.

61. Added a warning on the ITC inputs that users should also change RPS PPA prices because they include embedded ITC assumptions.

62. Added documentation on why the adoption curve parameters were chosen.

63. Completed other formatting and in-tool documentation changes.

64. The billing determinants database now closes after the public tool model run is complete.

65. The VBA code that executes the model has been modified to be compatible with both mac and PC computers

66. Corrected the cell reference in the monthly demand charge cell in the rate calculator tab so that it no longer refers to a previously deleted cell. This error only affected residential demand charges for NEM successor participants.

67. Diablo Canyon capital costs were removed from the forward stream of capital expenditures post 2024 when Diablo Canyon is assumed to be retired.

68. Linked the ‘Marginal Avoided Subtransmission Cost Multiplier’ on the ‘Key Driver Inputs’ tab to marginal avoided subtransmission costs.

69. Corrected the dollar year used in the marginal transmission avoided cost calculations on the ‘Avoided Cost Calcs’ and ‘Pub to RR’ tabs.

70. Corrected $/kW-yr value in row 4046 by dividing the $/kW-yr value by hours times the weighted average capacity factor of renewables in each year.

71. Recalculated DDMSF billing determinants.

72. Adjusted the pre-populated default rates for SDG&E non-residential customers.

73. Corrected the model logic to only apply user-input NEM Successor non-bypassable treatment (Ex. cell E51 on the ‘Basic Rate Inputs’ tab) to participants that install DER in 2017 or later.

74. Clarified that the unit for grid charges based on DER nameplate capacity is $/kW AC and not $/kW DC on the ‘Basic Rate Inputs’ and ‘Advanced Rate Inputs’ tabs.

75. Added an output for non-bypassable charges in the 'Detailed Rate Outputs' section of the 'Results' tab.

76. Updated the default residential rates to reflect the July 3rd Decision on Residential Rate Reform, D.15-07-001. Created three default residential rate structures: 2 tiered, TOU 1 with a 2-8pm on peak period, and TOU 2 with a 4-8pm on peak period. Saved "High" and "Low" scenarios with each of these rate structures.

77. Updated some unused rate inputs in the saved scenarios.